Power in Indonesia

Investment and Taxation Guide

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Regulatory information current to 9 September 2016.

Contents

Glossary

Term	Definition
ADB	Asian Development Bank
APLSI	The Independent Power Producers Association (*Asosiasi Produsen Listrik Swasta Indonesia*)
BAPPENAS	National Development Planning Agency (*Badan Perencanaan Pembangunan Nasional*)
BKPM	Investment Coordinating Board (*Badan Koordinasi Penanaman Modal*)
BOO	Build Own Operate
BOT	Build Operate Transfer
DEN	The National Energy Council (*Dewan Energi Nasional*)
DGE	Directorate General of Electricity (*Direktorat Jenderal Ketenagalistrikan*)
DPR	House of Representatives (*Dewan Perwakilan Rakyat*)
EBTKE	New and Renewable Energy and Energy Conservation (*Energi Baru, Terbarukan dan Konservasi Energi*)
EPC	Engineering, Procurement and Construction
FTP I	The fast track program introduced in 2006 mandating PLN to build 10 GW of coal-fired plants across Indonesia
FTP II	The fast track program introduced in 2010 to build 10 GW of power plants focusing on renewable energy sources and IPP involvement
GoI/Government	Government of Indonesia
GR	Government Regulation (*PP* or *Peraturan Pemerintah*)
GW	Gigawatt (1,000 MW)
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")
INAGA	Indonesia Geothermal Association
IO	Operating Permit for Generating Electricity for Own Use (*Izin Operasi*, sometimes referred to as *Izin untuk Mengoperasikan Instalasi Penyediaan Tenaga Listrik untuk Kepentingan Sendiri* - "IUKS")
IPB	Geothermal Permit under 2014 Law (*Izin Panas Bumi*)
IPP	Independent Power Producer

Term	Definition
ISAK	Interpretations of Indonesian Financial Accounting Standards (*Interpretasi Standar Akuntansi Keuangan*)
IUP - Geothermal	Geothermal Permit under 2003 Law (*Izin Usaha Pertambangan - Panas Bumi*)
IUP	Mining Business Licence (*Izin Usaha Pertambangan*)
IUPK	Special Mining Business Licence (*Izin Usaha Pertambangan Khusus*)
IUJPTL	Electricity support services licence (*Izin Usaha Jasa Penyediaan Tenaga Listrik)*
IUPTL	Electricity Supply Business Permit (*Izin Usaha Penyediaan Tenaga Listrik* sometimes referred to as *Izin untuk Melakukan Usaha Penyediaan Tenaga Listrik untuk Kepentingan Umum* - "IUKU")
JBIC	Japanese Bank for International Cooperation
JOC	Joint Operating Contract
KPPIP	The Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas*)
KP3EI	The Committee for the Acceleration and Expansion of Indonesia's Economic Development (*Komite Percepatan dan Perluasan Pembangunan Ekonomi Indonesia*)
kWh	Kilowatt hour
kV	Kilovolt
MKI	The Indonesian Electrical Power Society (*Masyarakat Ketenagalistrikan Indonesia*)
MoEMR	Ministry of Energy and Mineral Resources (*Kementerian Energi dan Sumberdaya Mineral*)
MoF	Ministry of Finance (*Kementerian Keuangan*)
MoSOE	Ministry of State-Owned Enterprises (*Kementerian Badan Usaha Milik Negara*)
MSW	Municipal Solid Waste
MW	Megawatt
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	Hydro Power Plant (*Pembangkit Listrik Tenaga Air*)
PLTB	Wind Farm (*Pembangkit Listrik Tenaga Bayu*)
PLTD	Diesel Fired Power Plant (*Pembangkit Listrik Tenaga Diesel*)

Term	Definition
PLTG	Gas Fired Power Plant (*Pembangkit Listrik Tenaga Gas*)
PLTGU	Combined Cycle Power Plant (*Pembangkit Listrik Tenaga Gas Uap*)
PLTMG	Machine Gas Fired Power Plant (*Pembangkit Listrik Tenaga Mesin Gas*)
PLTP	Geothermal Power Plant (*Pembangkit Listrik Tenaga Panas Bumi*)
PLTU	Steam Fired Power Plant (Coal) (*Pembangkit Listrik Tenaga Uap*)
POME	Palm Oil Mill Effluent
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PPU	Private Power Utility (electricity generated for own use)
PR	Presidential Regulation (*Perpres* or *Peraturan Presiden*)
PSAK	Indonesian Financial Accounting Standards (*Pernyataan Standar Akuntansi Keuangan*)
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 setup to support infrastructure financing in Indonesia)
RUKD	Regional Electricity Plan (*Rencana Umum Ketenagalistrikan Daerah*)
RUKN	National Electricity Master Plan (*Rencana Umum Ketenagalistrikan Nasional*)
RUPTL	Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SOE	State-owned Enterprise
TKDN	Local content (*Tingkat Komponen Dalam Negeri*)
WKP	Geothermal Working Area (*Wilayah Kerja Pertambangan*)

Foreword

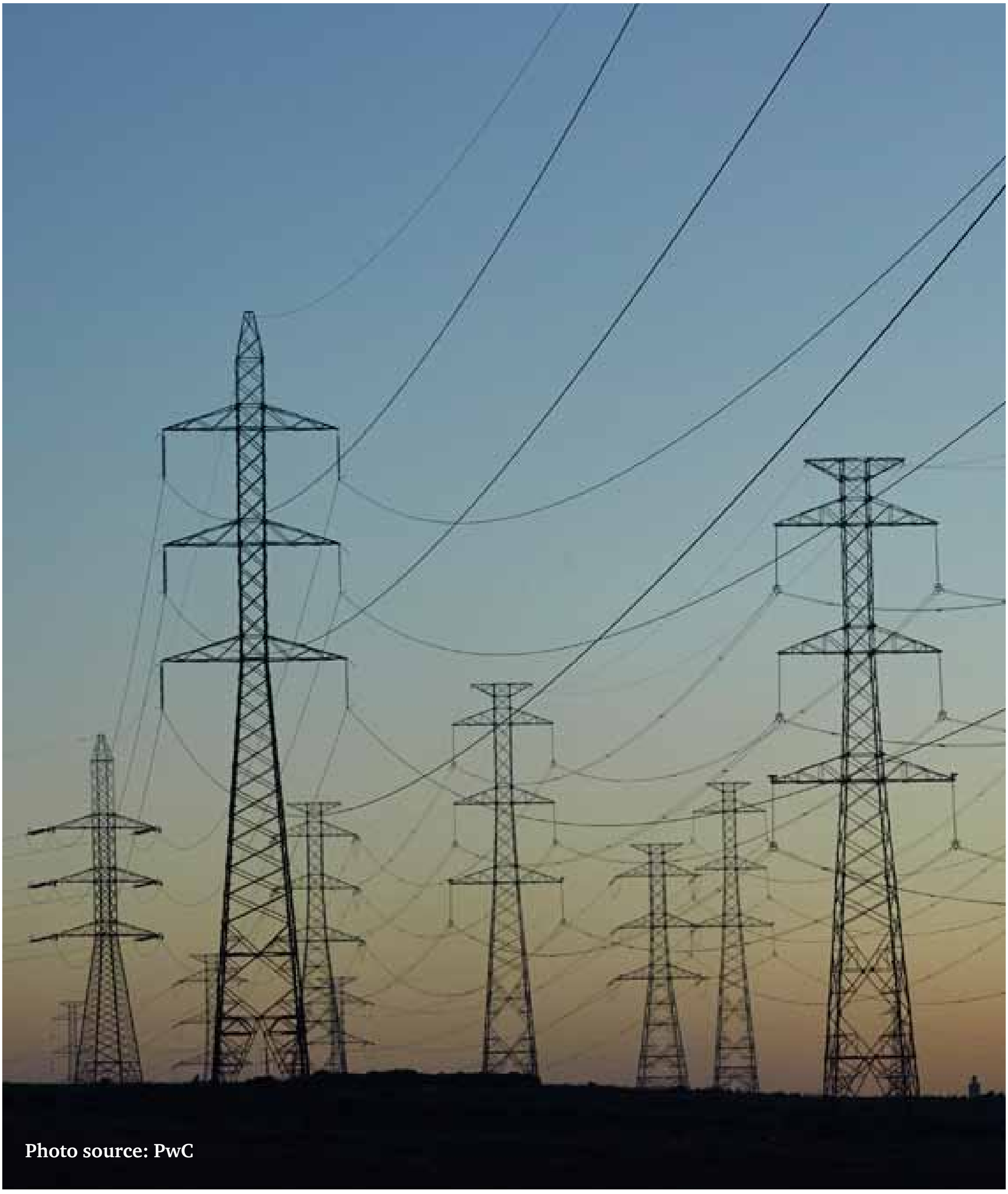


Photo source: PwC

Welcome to the Fourth edition of the PwC Indonesia "Power in Indonesia: Investment and Taxation Guide".

This publication has been written as a general investment and taxation guide for all stakeholders and those interested in the power sector in Indonesia. We have therefore endeavoured to create a publication which can be of use to existing investors, potential investors, and others who might have a more casual interest in the status of this economically critical sector in Indonesia.

We have updated and expanded this year's version to include more detail on Government's plans and a more detail discussion of trends in the conventional and renewable energy sectors.

As outlined in the table of contents page, this publication is broken down into chapters which cover the following broad topics:

- An overview of Indonesia's Power Sector;
- An overview of the legal and regulatory framework;
- A detailed look at IPP investment;
- The use of conventional energy sources;
- A dedicated section on the use of renewable energy;
- An outline of key tax issues; and
- An outline of key accounting issues.

As many readers may be aware, Indonesia's power generation infrastructure will need substantial investment if it is not to inhibit Indonesia's economic growth. Generation capacity, currently at around 55.5 GW, is struggling to keep up with the electricity demand from Indonesia's growing middle class population and its manufacturing sector. This issue is a key priority of the Government led by President Joko "Jokowi" Widodo. In late 2014, President Widodo outlined an ambitious plans for infrastructure development generally and power generation in particular, by announcing the goal of adding 35 GW of capacity over the next five years.

In early 2016, by way of Presidential Regulation No. 4/2016 (PR No. 4/2016) on the Acceleration of Power Infrastructure Development, President Widodo has reiterated a commitment to the 35 GW program by seeking to address the various issues affecting power project development in Indonesia. Amongst other measures, PR No. 4/2016, provides for a Government guarantee for the development of power projects by PLN and those projects developed by PLN in cooperation with Independent Power Producers (IPPs) or their subsidiaries, as well as addressing licensing, land acquisition and various other issues. Nevertheless, realising the ambitious goal of the 35 GW program will still require massive new investment in power generation capacity using both fossil fuel feedstock and renewable energy as well as transmission and distribution infrastructure.

In June 2016, the Minister of Energy and Mineral Resources had just issued the much anticipated 2016 – 2025 Electricity Supply Business Plan (*Rencana Umum Penyediaan Tenaga Listrik* – the "2016 RUPTL") which in previous years was usually issued in January/February. The 2016 RUPTL aims to achieve an electrification ratio of 99.7% by 2025. To achieve this level of electrification, PLN and IPPs may need to construct at least 80.5GW of power plants by 2025 with 18.2 GW of plants planned to be constructed by PLN and 45.7 GW by IPPs (16.6 GW is currently not yet allocated between PLN and IPPs). To build this level of new capacity, PLN and IPPs will need to invest at least US$31.9 billion and US$78.2 billion, respectively. As such, for the next ten years, the private sector will play a greater role than ever before in the Indonesian power sector.

The 2016 RUPTL also focuses on achieving the target 23% renewables share in the energy mix, as dictated by the 2014 National Energy Policy. Given the current low level of power generation from renewables, achieving the targeted 23% share of the energy mix from renewables by 2025 means that renewable power generation should represent at least 25% of the power generation mix by 2025. As such, an increasing role for renewable energy sources in the Indonesian power sector is also envisaged.

To help encourage private investment in power generation capacity the Government has, since 2014, increased the feed-in-tariffs that PLN must pay to IPPs from a variety of feedstocks, in particular for renewable energy power generation, and sought to mitigate land acquisition and other issues. While the focus continues to be on large scale coal-fired power projects, including mine-mouth coal-fired power projects, there are also opportunities for private investment in gas and renewable energy projects. It is also hoped that the latest geothermal law will breathe life back into geothermal energy investments. Smaller-scale hydro, solar, wind and biomass projects are also attracting local and foreign investor interest.

Our view on the effectiveness of the policies continues to be optimistic, with the case for investment in power generating capacity being compelling. In an increasingly energy-hungry world with an epicentre of growth focused on Asia, Indonesia should be an important focus of any power investor's attention. Understanding the development of the regulatory and investment issues affecting Indonesia's power landscape is therefore of vital importance.

It is hoped that this guide will provide readers with some of the information necessary to better understand these dynamics.

This guide is not intended to be a comprehensive study on all aspects of the power industry in Indonesia but rather a general guide to certain key considerations related to investment and taxation in the sector. Readers should note that this publication is largely current as at 9 September 2016. Whilst every effort has been made to ensure that all information was accurate at the time of printing, many of the topics discussed are subject to interpretation and continuously changing regulations. In addition, some Government's plans/programmes are sometimes inconsistent with each other. As such, this guide should not be used as a substitute for up-to-date professional advice. Please contact your usual PwC contact, or any of the specialists listed on page 165 for further information.

We hope that you find this publication of interest and wish all readers success with their endeavours in the Indonesian power sector.

Photo source: PwC

1. Overview of Indonesia's Power Sector

Photo source: PwC

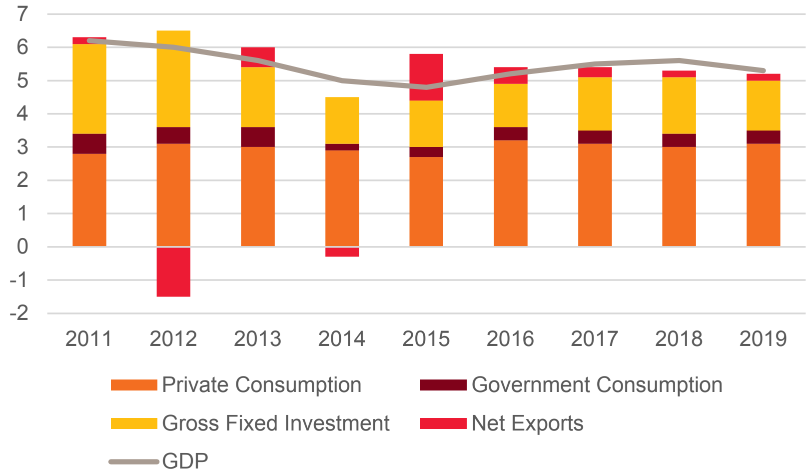
1.1 Demand for and supply of power in Indonesia

Indonesia is an archipelago with over 18,000 islands, and had a population of over 255 million people in 2015.[1] This makes it the world's fourth most populous country, and the largest economy in Southeast Asia.

In 2013, the Indonesian economy entered a slowdown period as global commodity prices fell, exacerbated particularly by the slowdown in the Chinese economy. GDP growth in 2013-2015 averaged 5%, compared to above 6% growth since 2009. In 2016, as uncertainty around the elections subsided and President Widodo's initiatives on Government's infrastructure spending and regulatory and subsidy reforms began to be felt, the outlook has improved; the World Bank forecasts growth of 5.1% this year (2016), and the Economist Intelligence Unit forecasts average growth of 5.3% until 2019. The Rupiah appears to have stabilized in the range 13,000 – 13,500 per US Dollar ("USD") in Q2 2016.

This forecast is largely driven by domestic household consumption on the expenditure side (see Figure 1.1), as no major uptick in commodity and energy prices is expected in the medium-term. On the supply side, key sectors have historically included manufacturing (24% of GDP), agriculture (14%), trade, hotels and hospitality (14%), mining (11%) and construction (10%). With the current slowdown in the mining sector, some rebalancing of economic growth towards manufacturing is likely to take place over the next 5 years. Industrial activity is also expected to expand outside the traditional industrial heartlands of Western/Central Java and DKI Jakarta to Eastern Java, Southern Sumatera and Kalimantan.[2]

Figure 1.1 - Historical and Forecast GDP Growth and Contribution by Expenditure Item (% p.a.)



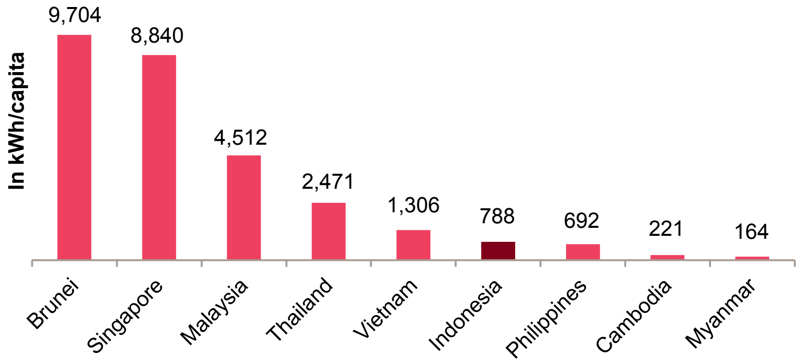
Source: Economist Intellegence Unit, February 2016

1 Bps.go.id
2 PwC and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016, p. 15. https://www.pwc.com/id/en/pwc-publications/industry-publications/energy--utilities---mining-publications.html

Demographics are also in Indonesia's favour. The country has an expected emerging middle class of some 74 million, and has already undergone an unprecedented degree of urbanisation and industrialisation, which is likely to continue. The Government of Indonesia (the Government or the "GoI"), expects population growth to continue at 1.0% p.a. until 2030.

Currently, access to electricity and electricity consumption varies across the archipelago. Electricity consumption in 2013 was 788 kWh per capita on a national basis, lower than regional competitors (see Figure 1.2), although consumption is higher in more industrialised areas, such as the western part of Java. Even based on the 2015 consumption of 910 kWh per capita,[3] Indonesia is still well behind its neighbouring economies. Similarly, in terms of access to the grid, the picture is mixed, with electrification in the western part of the country as high as 99.97% (Bangka Belitung), and in the eastern part of the country as low as 45.9% (Papua) (see Figure 1.3). The national average in 2015 was 88.3%.[4] Based on the 2016 - 2025 PLN Electricity Supply Business Plan (*Rencana Umum Penyediaan Tenaga Listrik* – the "2016 RUPTL"), the electrification ratio is planned to increase to 97.4% by 2019 and to 99.7% by 2025.

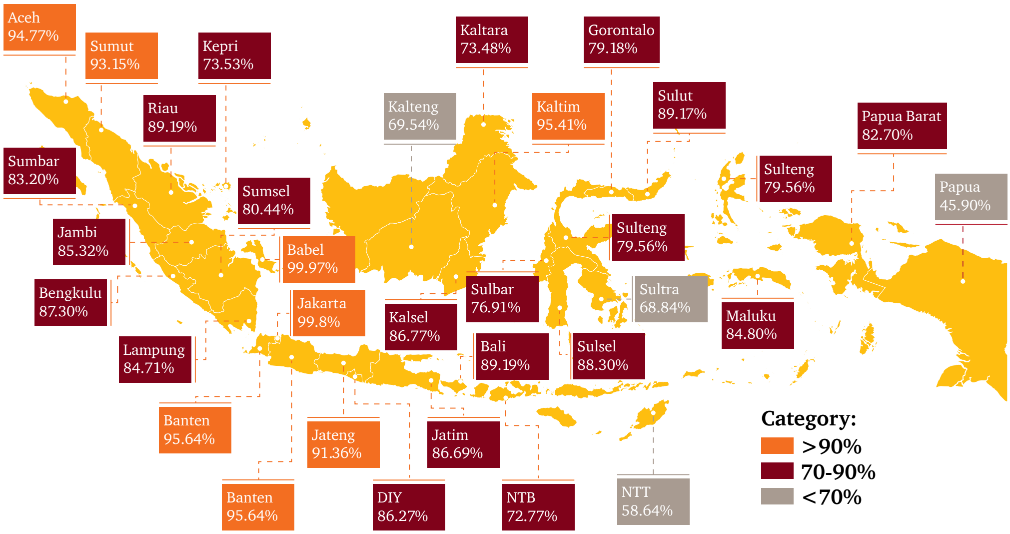
Figure 1.2 - 2013 Electricity consumption per capita in major ASEAN countries



Source: IEA Statistics 2014

3 *Direktorat Jenderal Ketenagalistrikan, "Upaya Pemenuhan Kebutuhan Listrik Nasional", Presentasi dalam Koordinasi dan Supervisi (Korsup) Energi Tahun 2016 antara KESDM dengan KPK RI, Balikpapan, 6 April 2016* [Directorate General of Electricity ("DGE"), "The Effort to Fulfil National Power Needs", Presentation in the 2016 Energy Coordination and Supervision between the Ministry of Energy and Mineral Resources (the "MoEMR") and Corruption Eradication Commission, Balikpapan, 6 April 2016].
4 *Laporan Akuntabilitas Kinerja Instansi Pemerintah Kementerian ESDM 2015 ("LAKIP KESDM 2015")* [2015 Ministry of Energy and Mineral Resources Performance Accountability Report], p. 73.

Figure 1.3 - 2015 Electrification Rates in Indonesian Provinces



Source: LAKIP KESDM 2015

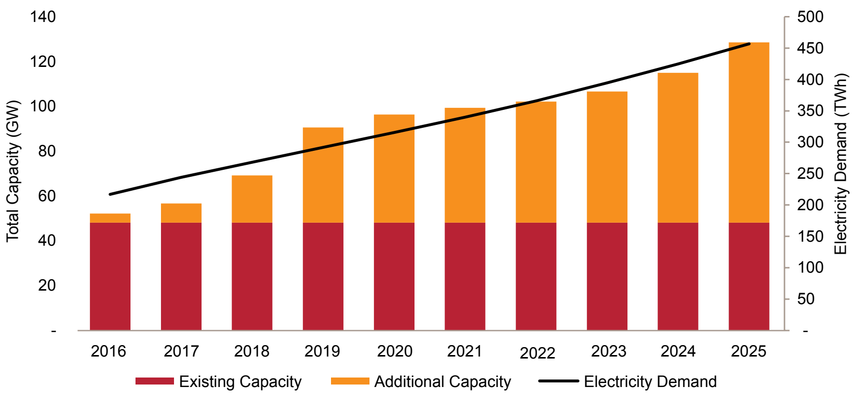
The number of customers of the national electricity company PT Perusahaan Listrik Negara ("PLN") has increased by approximately 8% p.a. from 42.4 million in 2010 to 61.2 million in 2015. These customers comprise residential (56.6 million, 92.6%), commercial (2.9 million, 4.7%), industry (0.1 million, 0.1%) and other (1.6 million, 2.6%) customers. Residential customers are the most populous group, consuming 43.7% of the total electricity sold by PLN. Industry is the next biggest group, consuming 31.6% of electricity sold by PLN. The remaining 24.7% is consumed by commercial and other customers. Geographically, most consumers are located in Java-Bali (approximately 74.4% of total customers). Customers in Sumatera account for approximately 15.4%, with the remainder located in Kalimantan and the eastern part of Indonesia.[5]

Together, Indonesia's rising population (in particular the middle class population), rising per capita income and structurally lower electrification ratio imply fast growth in electricity demand in the future. Indeed, PLN projects electricity demand growth of around 8.5% p.a. between 2015 and 2025, reaching a total of 457 TWh of electricity consumed in 2025, compared to 203 TWh in 2015.[6] To meet this demand, the Government is planning to develop 35 GW of additional power capacity between 2015 and 2019, and a further 45 GW by 2025 (see Figure 1.4). This is part of the Government's wider plan for infrastructure support (as outlined in the Medium Term Development Plan 2015-2019) including road, rail, seaport and airport development, water supply and treatment, oil refining, gas supply and distribution and fibre-optic broadband. The 35 GW programme is also intended to improve Indonesia's power systems, which are currently on "alert" status because there are only four systems that

5 PLN Annual Reports 2010 – 2015 and 2015 PLN Statistics.
6 2016 RUPTL, p.126 and 2015 PLN Annual Report, p.18.

have adequate power reserves, while the remaining 19 systems are in deficit (regular rolling blackouts) or on "alert" status (reserve is less than the capacity of the largest power plant) (see Figure 1.5).

Figure 1.4 - Electricity Capacity (GW) and Demand (TWh) 2016 - 2025



Source: 2016 RUPTL

Figure 1.5 - Condition of National Power System

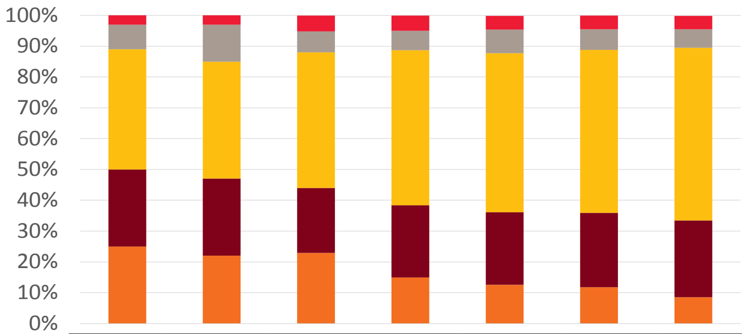
Source: DGE (6 April 2016)

1.2 Sources of energy

In 2015, Indonesia had approximately 55.5 GW installed capacity of power plants which generated 228 TWh of electricity. The current power generation fuel mix includes coal (56.0%), gas (24.9%), oil (8.6%) and renewables (10.5%).[7]

The new power plants in the 35 GW programme will be largely fossil fuel-based in the short term, with approximately 60% of power expected to be generated from coal by the end of 2019, compared to 56% in 2015. Second to coal is projected to be gas, maintaining a share of approximately 26.4% of the fuel mix in 2019 compared to 25% in 2015. However, an increasing role for alternative and renewable energy sources is envisaged.

Figure 1.6 – Development of Fuel Mix for Power Generation

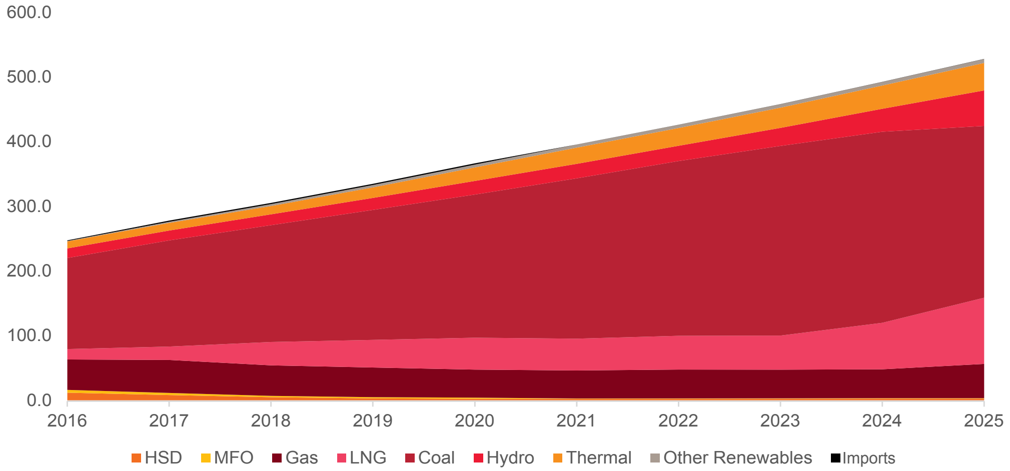


	2009	2010	2011	2012	2013	2014	2015
Oil	25.00%	22.00%	22.95%	14.97%	12.54%	11.81%	8.58%
Gas	25.00%	25.00%	21.00%	23.41%	23.56%	24.07%	24.89%
Coal	39.00%	38.00%	44.05%	50.27%	51.59%	52.87%	56.06%
Hydro	8.00%	12.00%	6.80%	6.39%	7.73%	6.70%	5.93%
Geothermal	3.00%	3.00%	5.13%	4.85%	4.42%	4.44%	4.34%
Other NRE	0.00%	0.00%	0.07%	0.11%	0.16%	0.11%	0.20%

Source: LAKIP KESDM 2015

7 DGE (6 April 2016),*op. cit*.,p.2.

Figure 1.7 - 2016 - 2025 Electricity Generation (in TWh)



In TWh

No	Fuel Type	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	High Speed Diesel	11.8	8.1	4.8	3.0	2.3	2.3	2.4	2.5	2.6	2.6
2	Marine Fuel Oil	4.4	3.3	2.1	1.9	1.8	0.5	0.6	0.6	0.7	0.7
3	Gas	47.0	51.0	47.2	45.8	43.3	43.3	44.6	44.3	44.7	52.9
4	Liquified Natural Gas	16.1	20.7	36.1	42.7	49.3	49.2	52.2	52.7	71.9	102.4
5	Coal	140.8	164.2	180.6	201.0	221.4	247.9	270.2	293.3	295.5	265.6
6	Hydro	14.9	15.3	16.8	18.6	21.1	22.4	23.6	27.9	35.5	55.0
7	Geothermal	10.9	11.8	12.8	16.3	20.9	25.0	27.5	31.3	36.0	42.5
8	Other renewables	0.6	1.8	3.0	3.7	4.4	4.8	5.0	5.4	5.5	6.0
9	Import	1.0	1.8	1.8	1.8	1.9	0.1	0.1	0.2	0.2	0.3
	Total	**247.5**	**278.0**	**305.2**	**334.8**	**366.4**	**395.5**	**426.2**	**458.2**	**492.6**	**528.0**

Source: 2016 RUPTL

The large role for fossil fuels reflects Indonesia's natural hydrocarbon abundance, as outlined in detail in Chapter 4 - Conventional Energy. Key factors and trends in the three major conventional energy sectors include:

- **Coal**: Thermal coal forms the single largest share of the fuel mix today (56%) and is expected to form a slightly lower share (50%) in 2025. Economics and logistics favour coal's ongoing dominance: it is a low-cost fuel that is easy to extract and transport using existing infrastructure. Indeed, little alternative economic option exists for low-rank coal, other than coal mine-mouth power generation. However, despite Indonesia's large geological reserves, it is unclear if current market prices and mining policies can incentivise sufficient investment in exploration and production for the full needs of the 35 GW programme.[8]

8 PwC and Indonesian Coal Mining Association ("ICMA"), "Supplying and Financing Coal-Fired Power Plants in the 35 GW Programme", March 2016, p. 28. http://www.apbi-icma.org/wp-content/uploads/2016/03/03-03-2016-APBI-PwC-Report-on-Supplying-and-Financing-the-35-GW-program-FINAL-FINAL-rev-8-32016.pdf

- **Natural Gas**: Natural gas power generation is expected to increase by 2.5 times by 2025 (in kWh terms) or from 24.9% of the overall mix in 2015 to 29.4% in 2025. Given the risks of not reaching the renewable energy target, and the fact that gas has been determined as the substitute fuel in the event of any shortfall in renewables generation, it is possible that its share could be even higher. As a relatively low-carbon, medium-cost fuel, and given Indonesia's extensive gas reserves, it is likely to remain a favoured fuel for at least the next decade. A glut of global and Asian Liquefied Natural Gas ("LNG") is likely to stimulate consumption further, although the fact that Indonesia is moving closer to being a net energy importer despite its abundant reserves may check this trend. Certainty on the upstream investment climate and improved physical infrastructure (both pipeline and Floating Storage Regasification Units ("FSRU")) are crucial to enabling a strong long-term role for gas in the Indonesian power generation mix.
- **Oil**: Oil is largely a relic of Indonesia's days as a net oil exporter, and transporting diesel fuel to remote areas is difficult and expensive. Power generation from refined oil products such as heavy fuel oil and diesel accounted for 8.6% of the fuel mix in 2015, but is planned to be nearly phased out (0.6%) by 2025, on account of their high cost (even at today's lower crude oil prices) and because refined fuel is generally imported.

Note that other forms of non-conventional, but fossil fuel, energy such as coal bed methane or coal gasification technologies also exist and are being developed in Indonesia. We do not explore these in this Guide because of the currently limited usage of those unconventional fuels in the power sector. For a full overview of the regulatory, tax and investment issues in the mining as well as oil and gas sectors, please see our separate Investment Guides.[9]

Indonesia also has enormous potential renewable resources, as outlined in Table 1.1 below. The potential renewable energy resources set out here is only based on a technical assessment, which does not consider the financial/economic viability of projects. Yet Government Regulation ("GR") No. 79/2014 on National Energy Policy (the "2014 NEP") requires the development of renewable energy resources to consider economic viability. The potential resource estimates in Table 1.1 also did not consider location (some renewable energy resources are located in areas of the grid with very low demand). Hence, 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/biogas	50 GW
Solar Photovoltaic ("PV")	4.80 kWh/m2/day
Wind Power	3 - 6m/s
Ocean	49 GW

Source: Rencana Strategis 2015 – 2019 Kementerian Energi dan Sumberdaya Mineral ("RENSTRA KESDM 2015 – 2019") [2015 – 2019 Strategic Plan of Ministry of Energy and Mineral Resources] and 2016 RUPTL

9 https://www.pwc.com/id/en/pwc-publications.html

However, renewable sources of energy are looking increasingly attractive in Indonesia, not only to support environmental policy around CO_2 emissions or urban air pollution, among other matters, but also on account of their improving cost profile and ability to be deployed in a more decentralised manner. Key factors and trends in the five major renewable energy sectors include:

- **Hydro**: Hydropower is currently the largest single source of renewable power in Indonesia, accounting for 6% of generation in 2015, and is expected to grow to 10.4% in 2025. Many prospective sites with good water flow and heads exist, but the sector is being held back by uncertainty regarding the approval of Power Purchase Agreements ("PPA"), and for mini-hydro by frequent changes and disagreements on the applicable Feed-in Tariff ("FiT") level,[10] as well as restrictions on foreign ownership. If seeking international finance, it is important that projects be robustly structured and prepared.
- **Solar PV**: Current solar PV deployment remains limited (under 100 MW) despite naturally high solar insolation across most parts of the country. The Supreme Court decision, announced in late 2015, to strike down the Minister of Energy and Mineral Resources Regulation ("MoEMR Regulation") No. 17/2013 on Solar FiTs is likely to have played a key role in slowing development. However, development activities led by the private sector and State-Owned Enterprises ("SOEs") appear to be continuing, and the global trend of rapid solar panel cost reduction should underpin better project economics. In July 2016, the MoEMR released supporting Feed-in Tariffs to replace MoEMR No. 17/2013 and support the deployment of an additional 5,000 MW of solar Photovoltaic ("PV") capacity. More than 400 MW of Solar PV capacity has been included by PLN in the 2016 RUPTL.
- **Geothermal**: With Indonesia possessing the second-largest geothermal resources in the world, its share of the fuel mix is expected to almost double from 4.3% in 2015 to 8.0% in 2025. A key strength of geothermal is the ability to act as base-load power, offsetting one of the traditional weaknesses of renewable energy. However, there are only a limited number of concessions under development and PPA approval has been slow. Indonesian SOEs are playing a dominant role, and the largest Independent Power Producer ("IPP") project to date (Sarulla) is expected to become operational in 2016. Thirty works areas, which are listed in Chapter 5, are also planned to be auctioned this year or next year.
- **Bioenergy**: The bioenergy market is formed of discrete segments (such as agricultural/ plantation biomass wastes, Palm Oil Mill Effluent ("POME"), Municipal Solid Waste ("MSW"), and biodiesel). The market at the moment largely consists of power plants with 10 MW or less of capacity. Large technical potential for power plants remains, with significant agricultural waste and MSW currently being improperly disposed of, however, realising this potential will require changes in the regulatory and contracting environment, especially at the sub-national government level. In early 2016, the President approved PR No. 18/2016, to expedite the development of waste-based power plants in seven of Indonesia's larger cities.
- **Wind**: Historically, wind has not played an important role in the fuel mix. However, significant recent progress has been observed, with several hundred MW under development and under construction from Java to Sulawesi. A national, economically attractive FiT for large-scale wind may be needed to stimulate further development.

10 http://finance.detik.com/read/2016/05/03/194026/3203059/1034/esdm-dan-pln-sepakat-soal-harga-listrik-mikro-hidro

A large number of regulatory, financial and practical barriers will need to be overcome for Indonesia's full potential of renewables to be released. Barriers common to many technologies include matching supply and demand with better transmission and distribution infrastructure, and the need to establish strong local supply chains and expertise. The availability of finance for well-structured projects does not appear to be a primary barrier, although the limited number of players willing to fund early-stage development (risk equity) remains a limiting factor. Recognising this, the Government is focusing on reforms to promote renewables. Factors supporting renewable deployment include globally falling costs, national carbon emissions targets, the high cost of oil-based generation, especially in remote regions, regulatory and physical barriers to gas distribution, substitute demand for gas and oil in industrial and transport use, and Government-provided feed-in tariffs and tax incentives.

Further discussion 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"), the electricity tariffs need no longer be uniform throughout Indonesia, and thus may differ according to operating areas or *Wilayah Usaha*. Tariffs are differentiated by end user group. In general, electricity tariffs are set by taking into account the ability of customers to pay, as well as the installed power capacity of each customer group. The higher the installed power, the higher the tariff imposed. The higher the electricity consumption, the higher the multiplier used for determining the tariff, in order to encourage customers to use electricity wisely. Different tariffs are subject to different subsidy arrangements; for example, small household tariffs are heavily subsidised with IDR 319/kWh representing a price more than four times lower than the average generation cost of IDR1,350/kWh in 2015.

Prior to 2013, PLN's revenue was dictated by regulated electricity prices, with tariffs set by the Central Government and ultimately approved by the Parliament, except for electricity prices in Kota Tarakan and Batam, which were approved by the respective Regional Governments. Since price increases require approval from Parliament, PLN's financial position was directly subject to the political process. Should the regulated price for electricity fall below the cost of production (which has generally been the case), the Ministry of Finance ("MoF") is required to compensate PLN via a subsidy. Since 2013, the electricity subsidy has stabilised due to the stabilisation of the average cost of generation, and the ability of PLN to pass on increases in inflation, the price of oil and the USD/IDR exchange rate to consumers (the "automatic adjustment mechanism") through MoEMR Regulation No. 31/2014 as amended by MoEMR Regulation No. 9/2015 (see Table 1.2). This subsidy includes a public service obligation ("PSO") margin, which was originally set in 2009 at 5% above the cost of electricity supplied. The margin was increased to 8% for 2010 and 2011 and then reduced to 7% from 2012.

Table 1.2 – Average Cost, Average Tariff and Subsidies

Year	Average Cost (Rp/kWh)	Average Tariff (Rp/kWh)	Subsidy (RpTrillions)
2011	1,351	714	93.2
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

Source: Statistik PLN 2015 [2015 PLN's statistics]

Furthermore, from January 2017 (which has been postponed until 1 January 2018), PLN will no longer automatically receive its Public Service Obligation ("PSO") subsidy of cost + 7% margin. It is now required to achieve certain performance targets each year in order to receive the subsidy, as required under MoF Regulation No. 195/2015, and the subsidy is to be gradually eliminated. The Government plans to have all households (except the very poorest) pay 'market prices' for electricity. However, this plan has not yet been approved by the House of Representatives (*Dewan Perwakilan Rakyat* – "DPR"). Tariffs for industry and certain residential customers are already non-subsidised.

1.4 Transmission and distribution ("T&D")

Being an archipelago nation made up of numerous islands, 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 all T&D asset ownership and operation, 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 are built by IPPs, in particular for power plants in remote areas, to connect the power plants to the closest PLN substations. However, ownership of these transmission lines will typically be transferred to PLN upon the completion of construction.

In 2015, transmission network consists of around 42,000 km circuits of transmission lines and 93,000 Mega Volt Ampere ("MVA") of substation transformer capacity. None of the major island groups is linked to another, with the exception of Java - Madura - Bali.

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

Island	20 - 30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatera	-	370	9,512	1,513	-	**11,395**
Java Bali	-	3,007	14,050	-	5,053	**22,110**
Kalimantan	-	123	3,004	-	-	**3,127**
Sulawesi	4	535	4,012	-	-	**4,551**
West Nusa Tenggara	-	-	256	-	-	**256**
Papua	-	244	-	-	-	**244**
Total	**4**	**4,279**	**30,834**	**1,513**	**5,053**	**41,683**

Source: 2015 PLN's statistics

A summary of substation transformer capacity for each significant island in Indonesia is as follows (in MVA):

Island	< 30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatera	-	600	10,113	910	-	**11,623**
Java Bali	-	2,581	44,983	-	28,000	**75,564**
Kalimantan	-	163	2,072	-	--	**2,235**
Sulawesi	30	821	2,038	-	-	**2,889**
Nusa Tenggara	-	-	240	-	-	**240**
Papua	-	100	-	-	-	**100**
Total	**30**	**4,265**	**59,446**	**910**	**28,000**	**92,651**

Source: 2015 PLN's statistics

During 2015, PLN was only able to build a 1,773 km circuits of additional transmission lines and 6,179 MVA of substation transformer capacity.[11] Based on the 2016 RUPTL, by 2025 Indonesia needs additional transmission lines of approximately 68,000 km circuits and substation transformer capacity of 172,000 MVA. In connection with the 35 GW programme, plans are underway to more than double the T&D network by 2019, with a 46,597 km circuits of additional transmission lines and 108,789 MVA of substation capacity.

Currently, there are already limited cross-border transmission lines connecting Indonesia and other ASEAN countries as part of the ASEAN Grid programme. Please refer to Section 2.2.5 (Cross-border sale and purchases) for a detailed explanation.

The 2016 RUPTL also plans for developing a well-known flagship project – the 500 kV High Voltage Direct Current (HVDC) transmission line connecting Sumatera and Java, which is planned to deliver electricity from coal mine-mouth power plants in Sumatera, to the more populous Java Island. Despite its inclusion in the RUPTL, there were reports in 2016 that PLN planned to reassess the feasibility of the HVDC project, given that the initial plan was developed back in 2004 – 2005 and may no longer suit current conditions. If the HVDC project is delayed or cancelled, the Sumsel 8, 9 and 10 power generation projects may also be cancelled or delayed (which would be a blow to those investors who have already invested much time and cost in bidding, or preparing to bid, for these projects).

In 2015, the current distribution network consisted of around a 350,000 km circuits of Medium Voltage Network, a 543,000 km circuits of Low Voltage Network, a 50,000 MVA of transformer capacity with a 406,000 transformers. During 2015, PLN was only able to build an additional 15,740 km circuits of distribution lines, and 33,136 km circuits for the medium and low voltage networks, respectively, as well as 3,596 MVA of transformer station capacity.[12]

11 2015 PLN Annual Report, p. 11.
12 *Ibid*., p. 308.

A summary of distribution lines for each significant island in Indonesia is as follows:

Island	Medium Voltage (in kmc)			Low Voltage (in kmc)	Number of transformers (in Unit)	Transformer capacity (in MVA)
	6 - 7 kV	10 - 12 kV	15 - 20 kV			
Sumatera	3	3	103,376	173,076	85,278	9,206
Java Bali	-	-	159,209	288,451	249,923	34,349
Kalimantan	2	-	29,924	32,104	27,191	2,689
Sulawesi	-	-	32,197	29,839	28,592	2,440
Nusa Tenggara	-	-	11,598	11,853	8,050	767
Maluku	-	-	6,241	3,272	3,268	285
Papua	-	-	4,426	4,525	3,232	415
Total	**5**	**3**	**346,971**	**543,120**	**405,534**	**50,151**

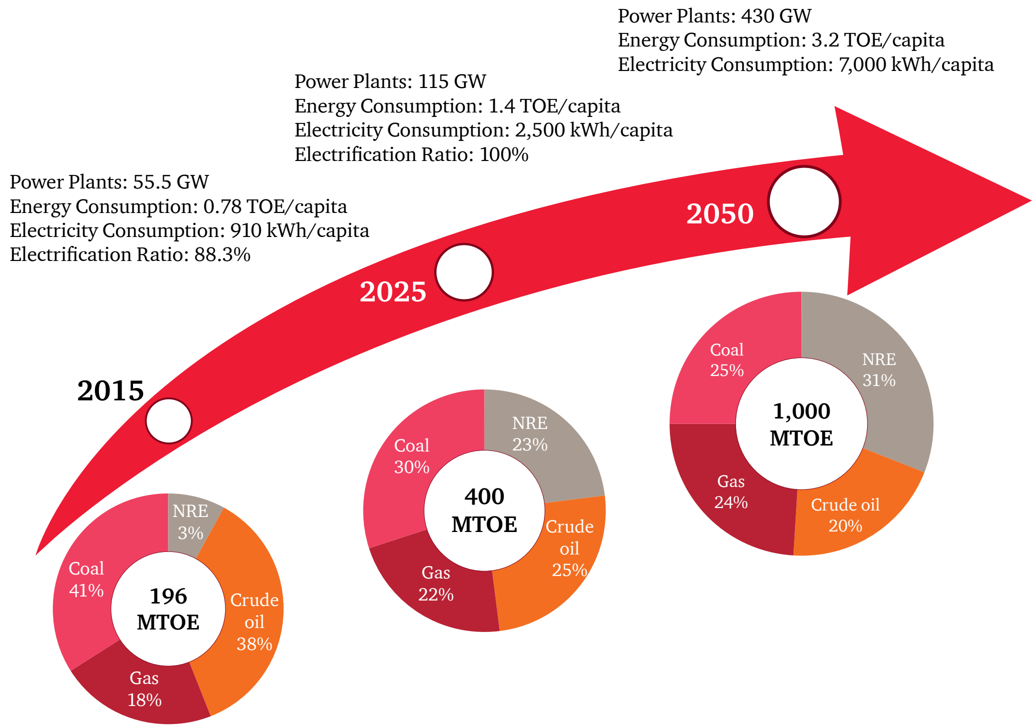
Source: 2015 PLN's statistics

Based on the 2016 RUPTL, by 2025 Indonesia needs an additional distribution capacity of approximately 159,100 km circuits and 133,200 km circuits for medium and low voltage networks, respectively, as well as 44,000 MVA of additional distribution transformer capacity.

1.5 Government's strategy, policy and plan for the power sector in Indonesia

Renewables have become more important recently due to concerns over global warming and other environmental issues, and certain technologies have become more attractive due to falling costs. This concern is shown in the targeted energy mix for primary energy demand in Indonesia. The renewable energy portion has increased to 23% based on the 2014 NEP compared to 17% based on PR No. 5/2006. In addition, the 2014 NEP also 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; (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. Further, the 2014 NEP also 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 TOE/capita and 3.2 TOE/capita, by 2025 and 2050, respectively.

Figure 1.8 - 2015 Energy Mix and the 2014 NEP target



Source: 2014 NEP, BP Statistical Review of World Energy June 2016 (65th edition), PwC Analysis

Key points in the 2014 NEP that directly relate to the power sector or act as a main reference to the power sector are as follows:

- To reach power generation installed capacity 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.
- 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 steps:

a) Utilisation of renewable energy from waterflow and waterfall, geothermal, sea wave, tidal and ocean thermal energy conversion and wind for electricity generation;
b) Utilisation of solar for electricity generation and non-electricity energy for industry, households and transportation;
c) Utilisation of biomass and waste for electricity generation and transportation;
d) Utilisation of natural gas for industry, electricity generation, households and transportation, specifically in cases that offer the highest value added;
e) Utilisation of coal for electricity generation and industry;

f) Utilisation of new solid and gas energy sources for electricity generation;
g) Utilisation of ocean thermal energy conversion as a prototype for early-stage connection to the power grid;
h) Utilisation of PV solar cells for transportation, industry, commercial buildings and households; and,
i) Maximise and make compulsory the utilisation of solar components and solar power plants that are produced domestically.

To create a competitive power sector, the Government shall, among other measures:
a) Determine the price 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 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 electricity subsidy in stages until the population's purchasing power can afford it without subsidy;
f) Encourage domestic capability to execute geothermal exploration and support the power industry.

To support the achievement of the new and renewable energy mix target based on the 2014 NEP, the power generation energy mix by 2025 should comprise approximately 25% new and renewable energy[13], 50% coal, 24% gas and 1% diesel fuel. In 2015, power generation from new and renewable energy was around 10%, and therefore to achieve 25% by 2025 represents quite an ambitious target. Based on the 2016 RUPTL, PLN projects that power generation from renewables will be only 19% by 2025. However, the Government has decided to allow PLN to use gas to meet any shortfall in renewables in the fuel mix for power generation.

1.6 Chronological development of the power sector in Indonesia

Early electricity arrangements in Indonesia were probably carried out pursuant to the 1890 Dutch Ordinance entitled the "Installation and Utilisation of the 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 for 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 its own use or for sale to PLN. Essentially the model involved allowing for 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 the power output, became the key driver of the commerciality of the entire value chain.

13 There are different targets for the share of renewables in the energy mix (23%) and the power generation fuel mix (25%).

The first major PPA in this new era was signed with PT Paiton Energy to develop the coal-fired Paiton power station in 1991. Several other significant IPPs followed, including a number in relation to geothermal power generation (under a slightly different investment framework). Many other IPP projects made it through various stages of licensing and commercial approval.

This IPP program, however, was effectively frozen in the late 1990s when the Asian financial crisis hit. Indonesia was badly affected, with GDP contracting by up to 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 from the devaluation of the Rupiah. A large portion of PLN's costs were denominated in US Dollars, including its PPA offtake prices, but its revenue base, from sales to consumers, was IDR-denominated. With the IPP sector set up for a USD denominated value chain, the investment economics of the entire sector deteriorated markedly, with around a 75% fall in the value of the local currency. Many of the IPPs that were not yet in production at that time were abandoned. Others could only continue with their PPAs renegotiated down to a much lower offtake price. Overall, a significant degree of investor confidence in the sector was lost. PLN was also left in a position of being unable independently to fund investment for 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 areas were 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.[14] The 2002 Electricity Law also allowed for electricity tariffs to be determined by the market and for independent regulation through the establishment of the Electricity Market Supervisory Agency.

However, in December 2004, Indonesia's Constitutional Court ruled the 2002 Electricity Law to be 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 from 1999 – 2004 there was very little private investment of any sort in new power projects.

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") and the Authorised Holder of an Electricity Supply for Public Use Business License (*Pemegang Izin Usaha Ketenagalistrikan untuk Kepentingan Umum*), which were essentially limited to PLN.

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

Other supporting legislation included:

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 responsible for coordinating policy related to the private provision of infrastructure;
c) PR No. 71/2006, which launched the first fast-track programme, and which also allowed direct selection for the first fast-track programme of coal fired power plants; and,
d) MoEMR Regulation No. 1/2006 on Electric Power Purchasing and/or Rental of Transmission Lines and MoEMR Regulation No. 5/2009 on 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 into 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) followed by a second programme (FTP II) in early 2010. Each programme aimed to accelerate the development of 10 GW of generation 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 of generation capacity.

In 2009 the Government passed the 2009 Electricity Law to strengthen the regulatory framework and provide a greater role for Regional Governments in terms of licensing and in determining electricity tariffs. The 2009 Electricity Law replaced the 1985 Electricity Law with effect from 23 September 2009. However, unlike the (intervening) 2002 Electricity Law, the 2009 Electricity Law does not eliminate the main role of PLN in the electricity supply business. Under the 2009 Electricity Law, electricity supply is controlled by the state but is conducted by the Central and Regional Governments through a state-owned enterprise. 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*) to participate in the electricity supply business. Refer to Section 2.2 for more detailed information on the 2009 Electricity Law.

1.7 Stakeholders

PLN

PLN is responsible for the majority of Indonesia's power generation, and has 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 the PKUK. PLN is now simply the holder of an IUPTL.

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

PLN's financial profile has improved in recent years due to full and prompt subsidy payments as regulated by Minister of Finance Regulation (MoF Regulation) No. 170/2013 (which is to be replaced by MoF Regulation No. 195/2015 effective from 1 January 2017 but postponed until 1 January 2018), an improvement in its fuel mix and automatic electricity price adjustments for some consumers based on the exchange rate, inflation and the Indonesian crude price through MoEMR Regulation No. 31/2014 as amended by No. 9/2015. In addition, in 2015, the MoF issued MoF Regulation No. 189/2015 on the "Procedure for Guarantee for Infrastructure Funding through Direct Loans from International Financial Institutions to State-owned Enterprises", whereby the Government will guarantee direct loans obtained from international financial institutions by SOEs that meet certain criteria in order to accelerate the provision of infrastructure to the public (credit enhancement). Further, under PR No. 4/2016, loans obtained by PLN in relation to the development of power infrastructure projects will also be fully guaranteed by the MoF.

MoEMR

The MoEMR is charged with creating and implementing Indonesia's energy policy, including the National Electricity Plan (*Rencana Umum Kelistrikan Nasional* – 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 implementing regulations related to electricity, NRE and energy conservation and 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 environment.

Commission VII is responsible for the approval of energy-related legislation (including electricty) and supervision of energy-related Government policy.

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 dan Swasta*), which facilitates cooperation in infrastructure projects between the Government and private investors.

Investment Coordinating Board (Badan Koordinasi Penanaman Modal – "BKPM")

From 2015, BKPM has issued electricity supply business licences. It acts as a "one-stop" integrated service for business start-up and licensing procedures as well as for facilitating foreign workers' permits. BKPM also offers an Investor Relations Unit for information and dealing with enquiries from existing and potential investors.

Please also see the discussion in Section 2.2.4 - Authority to issue IUPTL and other power-related licences, and 2.3.5 - Ease of licensing.

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. Other members of KPPIP include the Minister of Finance, the Minister of National Development Planning/Bappenas and the head of the National Land Agency. KPPIP was established with the main objective of coordinating the decision making process. KPPIP is the main contact in debottlenecking national strategically important and priority projects.

MoF

The MoF approves tax incentives that may be offered by the Government for a power project as well as any Government guarantees. The PPP Unit within the MoF is responsible for reviewing guarantee requests. Any approved guarantees are administered by PT Penjaminan Infrastruktur Indonesia ("PT PII") (see below).

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

Kementerian Negara 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 as well as assessing the achievement of those targets.

National Energy Council (Dewan Energi Nasional – "DEN")

DEN was formed in June 2009 to formulate a NEP, determine the National Energy General Plan (*Rencana Umum Energi Nasional*) and plan steps to deal with any future energy crisis. The DEN is chaired by the President and Vice-President with the Energy Minister as Executive Chairman. It has 15 members, which include the Minister of Finance, the Minister of Transportation, the Minister of National Development Planning/Bappenas, the Minister of Industry, the Minister of Agriculture, the Minister of Research, Technology and Higher Education, the Minister of Environment and Forestry and other stakeholders. The DEN's most recent NEP was approved by Parliament on 28 January 2014.

Committee for the Acceleration and Expansion of Indonesia's Economic Development (Komite Percepatan dan Perluasan Pembangunan Ekonomi Indonesia – "KP3EI")

KP3EI was established by the President in 2011 to coordinate the implementation of the Masterplan for the Acceleration and Expansion of Indonesia's Economic Development 2011 – 2025. KP3EI is headed by the President and includes teams covering: Regulations; Connectivity; Human Resources; and Science and Technology; and the Economic Corridors of Sumatra, Java, Kalimantan, Sulawesi, Bali and Nusa Tenggara, and Papua and Maluku Islands.

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

The IIGF was established on 30 December 2009 to provide guarantees for infrastructure projects. 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, with IDR6 trillion in capital injected as at the end of 2014. In 2015 and 2016, the Government further injected capital amounting to IDR1.5 trillion and IDR1.0 trillion, respectively. For further details please see Chapter 3.3.1 IIGF – for PPPs.

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

PT SMI was established on 26 February 2009 with IDR1 trillion (USD100 million) in capital. The capital was increased to IDR22.3 trillion by the end of 2015. PT SMI exists to help investors obtain domestic financing for the debt and equity funding of infrastructure development, including power projects. PT SMI is backed by multilateral agencies including the World Bank. The total financing commitment of PT SMI at the end of 2015 was IDR23 trillion, with 25% allocated to the power sector.

PT IIF was established on 15 January 2010 and operates as a private non-bank financial institution with an infrastructure project finance focus and with its shareholders being 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.

Indonesian Electrical Power Society (Masyarakat Kelistrikan Indonesia – "MKI")

MKI was established on 3 September 1998 and 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 members' views to the Government on topics such as technology, business environment and regulations.

Independent Power Producers Association of Indonesia (Asosiasi Perusahaan Listrik Swasta Indonesia – "APLSI")

APLSI serves as a forum for Indonesian IPPs to engage in dialogue with the Government on certain issues such as the renegotiation of tariffs for its members.

Indonesian Geothermal Association ("INAGA")

INAGA was established in 1991 as a forum for communication and coordination in order to improve its members' capabilities, understanding, cooperation and responsibility in relation to geothermal energy development in Indonesia. The organisation currently has about 600 individual members from various disciplines and 10 geothermal companies.

Indonesia 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, based in the UK. The management of METI also includes the Head of the Association of Hydro, Solar, Biofuel, Biomass, Biogas, and Wind Energy.


Photo source: PwC

2. Legal and Regulatory Framework

Photo source: PwC

2.1 Introduction

The power sector is regulated by MoEMR and its sub-agencies. These include the DGE and the DGNREEC.

The current regulatory framework is provided by the 2009 Electricity Law and the implementing regulations GR No. 14/2012 on Electricity Business Provision (as amended by GR No. 23/2014), GR No. 42/2012 on Cross-Border Sale and Purchase and GR No. 62/2012 on Electricity Support Business as well as other implementing regulations issued by the MoEMR, the Minister of Industry, the Minister of Finance, the Minister of Forestry and other Ministers with responsibilites relating to the electricity sector. There are also other laws and regulations that affect the sector such as Law No. 2/2012 on Land Procurement for Public Interest Development (the 2012 Land Acquisition Law) and its implementing regulation PR No. 71/2012 on the Implementation of Land Procurement for Public Interest Development (as amended by PR Nos. 40/2014, 99/2014 and 30/2015), which provide the framework for acquiring land for infrastructure projects. Further, there are also laws and regulations specific to various subsectors of electricity such as Law No. 21/2014 on Geothermal (the "2014 Geothermal 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.

2.2.1 RUKN and RUPTL

The MoEMR is responsible for developing the RUKN, which sets out, amongst other things, a 20 year estimate of electricity demand and supply, the investment and funding policy, and the approach to the utilisation of new and renewable energy resources. The RUKN is developed based on the NEP, which is currently stipulated under GR No. 79/2014, formulated by the Government after performing consultation with the DPR. The RUKN is reviewed at least every three years.

The 2009 Electricity Law also provides that Regional Governments should prepare a Regional Electricity Plan (*Rencana Umum Ketenagalistrikan Daerah* – "RUKD") based on the RUKN.

The RUPTL constitutes a 10 year electricity development plan in the operating areas, or *Wilayah Usaha* of PLN (excluding *Wilayah Usaha* of PLN's subsidiaries, PT Pelayanan Listrik Nasional Batam and PT Pelayanan Listrik Nasional Tarakan). The RUPTL is based on the Electricity General Plan (*Rencana Umum Ketenagalistrikan*) which consists of the RUKN and RUKD. The RUPTL contains demand forecasts, future expansion plans, electricity production forecasts, fuel requirements, etc and also indicates which projects are planned to be developed by PLN and IPP investors, respectively. Direct selection or direct appointments for IPPs to build power plants are based on the RUPTL. As such, the RUPTL is a very important document for all investors in the Indonesian power sector. The RUPTL is reviewed annually.

2.2.2 Electricity business

The 2009 Electricity Law divides the electricity business into the following two broad categories:

a) Activities involved in supplying electrical power (both public use and captive supply or "own use"):
   i) Electrical power generation;
   ii) Electrical power transmission;
   iii) Electrical power distribution; and,
   iv) The sale of electrical power.
b) Activities involved in electrical power support:
   i) Service businesses such as consulting, construction and installation, operation and maintenance, research and development, education, training and certification, and equipment testing and certification; and,
   ii) Industry businesses such as power tools and power equipment supply.

Electricity supply for public use can only be done in an integrated manner by one business entity within one *Wilayah Usaha*. Restrictions on *Wilayah Usaha* shall also apply to the supply of electricity for public use, which only includes power distribution and/or sales of electricity on a stand-alone basis.

Under the 2009 Electricity Law, the Government has given PLN priority rights over the electricity supply business throughout Indonesia except for certain *Wilayah Usaha* given to private enterprises, cooperatives, and self-reliant community institutions involved in the electricity supply business.

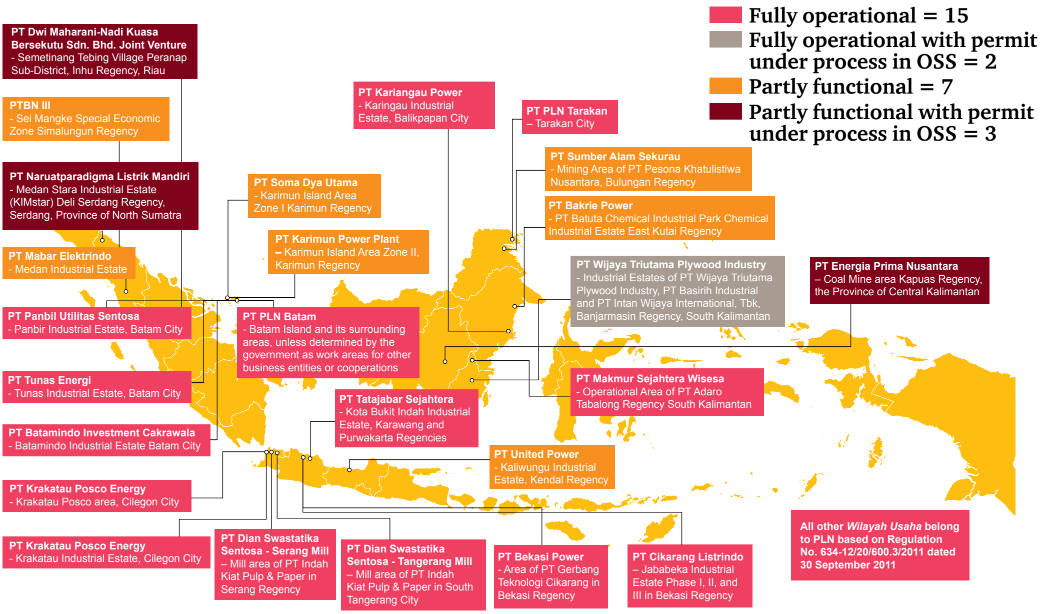
The DGE on behalf of the Minister of Energy and Mineral Resources sets *Wilayah Usaha* for electricity supply business. According to MoEMR Regulation No. 28/2012 (as amended by MoEMR Regulation No. 7/2016), *Wilayah Usaha* can be given to certain parties as described above, with the following conditions:

a. The area is not yet covered by an existing IUPTL holder;
b. The existing IUPTL holder in the *Wilayah Usaha* is not able to provide a good and reliable electricity supply or electricity distribution network; or
c. The holder of the *Wilayah Usaha* has returned some or all of the area to the MoEMR.

To obtain a *Wilayah Usaha*, SOEs, private enterprises, cooperatives, and self-reliant community institutions can make a request to the MoEMR through the DGE, supported by an analysis of the electricity need and business plan for the *Wilayah Usaha* being requested and a recommendation from the Governor or officer from the Provincial Government who has been given the authority to issue recommendations in cases where a *Wilayah Usaha* is within one province. The DGE will assign a technical team to assess the technical feasibility of the request to determine whether the requested *Wilayah Usaha* will be granted.

At the end of 2015, the Government had issued 27 *Wilayah Usaha* including *Wilayah Usaha* of PLN. The distribution of *Wilayah Usaha* can be seen in Figure 2.1.

Figure 2.1 – The holder of *Wilayah Usaha* in Indonesia in 2015



Source: DGE (6 April 2016), PwC Analysis

2.2.2.1 Generation

PLN and IPPs

As at the end of 2015, total installed capacity was 55.5 GW divided between PLN and its subsidiaries, which accounted for 38.3 GW (70%), IPPs accounting for 12.5 GW (21%), Private Power Utilities ("PPUs") accounting for 2.3GW (4%) and other providers with a non-diesel operating licence accounting for 2.4 GW (5%).[15] As such, the majority of power-generating assets in Indonesia are controlled by PLN, including by its subsidiaries including Indonesia Power, Pembangkitan Jawa Bali, PLN Batam and PLN Tarakan.

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 PR No. 14/2012 (as amended by PR No. 23/2014) and their implementing regulation, MoEMR Regulation No. 3/2015. A similar situation applies for PPPs under PR No. 38/2015. For a detailed discussion of the IPP/PPP procurement process, see Section 3.4 - Procurement process.

15 DGE (6 April 2016), *op.cit.*, p. 2.

PPUs

Investors who generate electricity for their own use rather than for sale to PLN are known as PPUs. PPUs with capacity greater than 200 kVA must hold an operating licence (*Izin Operasi*) to generate, transmit and distribute electricity for their own use or to their own customer base (such as tenants on an industrial estate).[16] PPUs with capacity between 25-200 kVA must obtain a Registration Letter from the relevant Minister, Governor or Mayor, and PPUs with capacity lower than 25 kVA must report to the relevant Minister, Governor or Mayor. The PPU may sell excess capacity to an IUPTL holder (in practice this is most likely to be PLN) or directly to end customers subject to the approval of the relevant Minister, Governor or Mayor. In cases in which PPUs are producing power for their own use and selling directly to other users (e.g. Industrial Estate tenants), PPUs will need a *Wilayah Usaha* and IUPTL permits in addition to an *Izin Operasi* to act as a power seller.

2.2.2.2 Transmission, distribution and retail

The 2009 Electricity Law provides PLN with priority rights to conduct its business throughout Indonesia. As the sole owner of transmission and distribution assets, PLN remains the only business entity involved in transmitting and distributing electrical power. Whilst the 2009 Electricity Law 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 open access for both transmission and distribution, currently private sector participation is in effect still limited to the power generation sector. This is set to change following the enactment of MoEMR Regulation No. 1/2015 on "power wheeling" which aims to allow IPPs and PPUs to use PLN's existing transmission and distribution networks. Power wheeling is the joint use of the networks to optimise the value of the networks and speed up the supply of additional generating capacity. However, implementing regulations setting out 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 classifies electricity support businesses into electricity-supporting services business and electricity-supporting industry business licences.

Based on GR No. 62/2012, an electricity-supporting service business covers:
a. Consulting 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 use of electricity;

16 For a detailed overview of the regulation and business models for PPUs in industrial estates see PwC and GE (2016).

i. Certification of electricity equipment adequacy and use of electricity;
j. Certification of electricity engineering competence; and,
k. Business or other services directly related to the provision of electricity.

Entities involved in electricity-supporting services business must have an Electricity Supporting Services Business License (*Izin Usaha Jasa Penunjang Tenaga Listrik* – "IUJPTL").

Electricity-supporting business is comprised of supporting industries for electricity equipment and for electricity utilisation. Entities involved in electricity-supporting industry business must have an Electricity Supporting Industry Business License (*Izin Usaha Industri Penunjang Tenaga Listrik* – "IUIPTL").

2.2.3 Local content

The 2009 Electricity Law requires holders of an IUPTL or an IUJPTL/IUIPTL to prioritise the use of domestic products and services. Minister of Industry Regulation ("MoI Regulation") No. 54/2012 stipulates the minimum required percentage of local goods and services (by value) used for the development of electricity infrastructure. Failure to comply with these local content requirements may result in administrative and financial sanctions.

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

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

Power Plant	Capacity	Minimum use of domestic products (TKDN)
Coal-fired	up to 15 MW	67.95% for goods; 96.31% for services and 70.79% for goods and services combined
	>15 – 25 MW	45.36% for goods; 91.99% for services and 49.09% for goods and services combined
	>25 – 100 MW	40.85% for goods; 88.07% for services and 44.14% for goods and services combined
	>100 – 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 – 50 MW	49.84% for goods; 55.54% for services and 51.60% for goods and services combined
	> 50 – 150 MW	48.11% for goods; 51.10% for services and 49% 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 domestic products (TKDN)
Geothermal	up to 5 MW	31.30% for goods; 89.18% for services and 42.00% for goods and services combined
	5 – 10 MW	21.00% for goods; 82.30% for services and 40.45% for goods and services combined
	10 – 60 MW	15.70% for goods; 74.10% for services and 33.24% for goods and services combined
	60 MW – 110 MW	16.30% for goods; 60.10% for services and 29.21% for goods and services combined
	>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 MW – 100 MW per block	35.71% for goods; 71.53% for services and 40.00% for goods and services combined
	100 MW – 300 MW per block	30.67% for goods; 71.53% for services and 34.76% for goods and services combined
	>300 MW per block	25.63% for goods; 71.53% for services and 30.22% for goods and services combined
Home Solar System	Per unit	30.14% for goods; 100% for services and 53.07% for goods and services combined
Communal Solar System	Per unit	25.63% for goods; 100% for services and 43.85% for goods and services combined

The construction of power plants is also regulated as follows:

- 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 shall be undertaken and led by a national Engineering, Procurement and Construction (“EPC”) company.
- The development of power plants other than those mentioned above can be undertaken by a consortium of a foreign company and a local company.

The following table summarises the minimum local content 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 19.237% for goods and services combined
Extra-High Voltage GIS	150	11.19% for goods; 26.68% for services and 17.389% for goods and services combined

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

Provisions and procedures for the calculation of local content in goods, services and the combination of goods and services for the respective power plants, main relay stations and transmission/distribution networks are regulated by MoI Regulation No. 15/M-IND/PER/2/2011 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 IUPTL

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:

a) An IUPTL 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 *Izin Operasi* to supply electricity for own use (i.e. for PPUs) with electricity capacity of more than 200 kVA, which may be issued for a maximum validity period of ten years and may be extended.

An IUPTL 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 IUPTL may be issued to the following entities:

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

From January 2015, BKPM, acting on behalf of the MoEMR, may issue ten types of power-related licences under MoEMR Regulation No. 35/2014, namely:

1. IUPTL
2. *Izin Operasi*
3. Determination of *Wilayah Usaha*
4. IUJPTL
5. Cross-border sale and purchase licence
6. Permit for utilisation of power grid for telecommunications, multimedia and informatics
7. Geothermal preliminary survey assignments
8. Geothermal licence (*Izin Panas Bumi*)
9. Geothermal support services approval
10. Geothermal explosives storage permit

2.2.5 Cross-border sale and purchase

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

Power can be sold across the Indonesian border only if:

a) The power needs of the local area and surrounds 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.

Power can be purchased from outside of Indonesia only if:

a) The purchase is intended to meet local electricity needs or to improve/enhance the quality and reliability of electricity supply;
b) Does not harm national sovereignty, security and economic development;
c) The purchase does not ignore the development of the capability of supplying electricity in the country; and,
d) The purchase does not result in dependence on the procurement of electrical power from other countries.

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

Historically, Indonesia has imported electricity from Malaysia. Purchases increased from 1.26 GWh in 2009 to 8.99 GWh in 2014 due to a shortage of power in West Kalimantan. Given the lack of power supply in West Kalimantan, the Government permitted the development of a 275 kV link between Sarawak, Malaysia and West Kalimantan to import hydro-generated power under a 25-year agreement between PLN and the Sarawak Energy Supply Corporation. This interconnection became live in January 2016. For the first five years, Indonesia is expected to import around 50 MW during non-peak load time and 230 MW at peak load time, after which PLN plans to export power on a net basis after the completion of the West Kalbar 1 (2 x 50 MW), Kalbar 2 (2 x 27.5 MW) and Kalbar 3 (2 x 55 MW) steam power plants.

The Sarawak-West Kalimantan link could be considered 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 flexibility for systems operators to match supply and demand at the lowest possible cost, supporting further intermittent renewable deployment, and increasing energy security. Such an ambitious project with large investment outlays will require a supportive cross-border regulatory environment, cooperation among national utilities on technical issues and more dynamic pricing in order to better match supply and demand.

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

Interconnection transmission network	Earliest Commercial Operation Date ("COD")
Peninsular Malaysia – Sumatera	2019
Batam – Singapore	2020
East Sabah – East Kalimantan	Post 2020
Singapore – Sumatera	Post 2020

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

2.3 PR No. 4/2016

A five-year 35 GW power generation programme was announced by President Joko Widodo in late 2014. The introduction of this 35 GW programme was seen as a continued effort from the Government to enhance Indonesia's electricity infrastructure. The Government had introduced FTP I of 10 GW of coal-fired power generation in 2006, and FTP II of 10 GW, coming largely from renewable energy projects in 2010. The realisation of FTP I and II has not been very promising. After almost ten years, the FTP I is not yet 100% completed. FTP II has not progressed as expected, and various projects in this programme have been integrated into the 35 GW programme under President Joko Widodo's administration.

Based on the experience and obstacles faced in FTP I and II, PR No. 4/2016 on the Acceleration of Power Infrastructure Development was issued to address various issues affecting power project development in Indonesia. This included, among other measures, a Government guarantee for the development of power projects, which covers both projects developed by PLN, and 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, an IPP can receive a business viability guarantee from the MoF for PLN's obligations under PPAs. To obtain such a guarantee, PLN's President Director needs to request the guarantee from the MoF before the start of the procurement process of the power projects. PR No. 4/2016 does not provide any criteria for an IPP project to be given a business viability guarantee or for a guarantee-granting mechanism. Hence, it is at the discretion of PLN to propose the guarantee. Further, the guarantee may also need to be included in the procurement documents; it is therefore questionable whether at least half of the 35 GW power development projects for which PPAs were signed in 2015, as well as projects tendered prior to the issuance of this PR, are eligible for this guarantee.

Under PR No. 4/2016, loans obtained by PLN in relation to the development of power infrastructure projects will also be fully guaranteed by the MoF. To obtain such a guarantee, PLN's President Director needs to request it from the MoF. The MoF must give its approval of PLN's request for a guarantee within 25 business days after the MoF receives a complete submission from PLN.

The procedures for obtaining the business viability guarantees for IPPs as well as loan guarantees for PLN are regulated under MoF Regulation No. 130/2016 (superceding MoF Regulation No. 173/2014).

2.3.2 New and renewable energy projects

Electricity infrastructure development is conducted by prioritising the utilisation of new and renewable energy in order to achieve the target proportion of new and renewable energy in the energy mix as required under the NEP. The Central Government and/or Local Governments can provide support in the form of: (1) fiscal incentives; (2) licensing and non-licensing relief;

(3) feed-in tariffs for new and renewable energy sources; (4) the establishment of a separate business entity to provide electricity generated from new and renewable sources of power to be sold to PLN; and (5) specific subsidies for new and renewable energy. This support will depend on the feasibility and economics of electricity infrastructure development. As such, PR No. 4/2016 only confirms a number of fiscal incentives available for new and renewable energy development.

It is clear that, based on in this PR, the Government plans to develop a new and renewable energy aggregator that will buy all the electricity generated from new and renewable energy and later sells it to PLN and receives specific subsidies for new and renewable energy. However, it is not clear when this new aggregator will be established, or whether it will be part of PLN or an independent SOE.

PR No. 4/2016 clarifies that hydro, geothermal and wind power projects, including the transmission lines, can be developed in Natural Reserve Areas and Natural Conservation Areas in accordance with the prevailing laws and regulations.

2.3.3 Local content

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

For details of the local content requirements, please see Section 2.2.3 - Local content.

2.3.4 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 and its implementing regulations) using shortest time frames (currently the maximum time period is set at 583 days – see further discussion in Section 2.4.4). 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 of not more than five hectares can be directly purchased by PLN, a subsidiary of PLN, or IPPs from holders of land rights in a purchase or exchange or by other means as agreed by both parties. If the landowner disagrees with the appraisal price, PLN, a subsidiary of PLN or an IPP can agree a purchase price above the appraisal price after performing a cost-benefit analysis considering good governance during the process. However, it is questionable whether a cost-benefit analysis can be implemented since this method is not prescribed in the 2012 Land Acquisition Law.

In the event that land acquisition for transmission and/or substations cannot be executed because the landowner disagrees with the price even when this is set above the appraisal price, PLN, a subsidiary of PLN or an IPP can rent, or lease, the land or cooperate with the landowners based on another agreement.

In the case of land to be acquired for electricity infrastructure development that is controlled by the people in a forest area, PLN, a subsidiary of PLN or an IPP should ask the National Land Agency to provide information on land ownership. The National Land Agency will provide information on land ownership in coordination with the minister responsible for the environment and forestry. If the National Land Agency states that the public does not have rights to land located in the forest area, PLN, a subsidiary of PLN, or an IPP will request a forest use permit. People who live in a forest area used for electricity infrastructure development will need to settle this with PLN, a subsidiary of PLN or an IPP together with other ministries/agencies and Local Government, taking into account their needs and social impacts. Settlements agreed will be regulated by a MoMER regulation.

The Central Government and/or Regional Governments provide support to PLN, a subsidiary of PLN, or an IPP by supporting land acquisition by giving them priority over the required land, and by providing state-owned/regional-owned land.

2.3.5 Ease of licensing

PR No. 4/2016 provides a platform to simplify the licensing process using one-stop services ("PTSP") at the BKPM as well as PTSP in provinces and regencies, and also to speed up the process of obtaining licences and non-licences (i.e. certain other permissions and documents) in relation to power projects in the following ways:

- PLN, subsidiaries of PLN or IPPs submit applications for licences and non-licences that are required to commence a power project to the PTSP at BKPM:
  a. IUPTL;
  b. Determination of location;
  c. Environmental licence;
  d. Borrow-to-use forest area permit (*Izin Pinjam Pakai*); and
  e. Building construction permit (IMB).

- PR 4/2016 provides a time limit for governmental authorities for licence issuance, as follows:
  a. For licences over which the authority for issuance has been delegated to BKPM: three working days;
  b. For licences over which the authority for issuance has not been delegated to BKPM: five working days, except those covered in points c-e below.
  c. Environmental licence: 60 working days;
  d. Borrow-to-use forest area permit: 30 working days; and
  e. Non-licence for taxation facility: 28 working days.

Note that the licence issuance time limits are counted from the day on which the complete application is submitted. If the governmental authorities find that an application is not complete, there is a three-day time limit for the governmental authorities to return the application.

- Licences for activities that do not endanger the environment are approved on the basis of a checklist of steps to be completed by the applicant during the project. The following licences will be in the form of checklist:
  a. IMB;
  b. Disturbance permit; and
  c. Approval for technical plan for building construction.

  For a checklist to be regarded as an approved permit, the applicant must submit a commitment to fulfil the checklist and register it with the national or regional PTSP, as applicable.

  Fulfilment of the checklist is mandatory for the recipient of the licences and the governmental authorities will oversee its fulfilment throughout the development process. Failure to fulfil the checklist will be subject to sanction in accordance with the applicable laws and regulations.

2.3.6 Spatial Plan (Tata Ruang)

PR No. 4/2016 has introduced the following stipulations related to spatial planning:

- In the event that power infrastructure development is not in accordance with the Spatial Plan, the detailed Detailed Spatial Plan for the Area, or the Zoning Plan for Coastal Areas and Small Islands where the power projects are built, then there can be a change in the Spatial Plan, the Detailed Spatial Plan Area, or the Zoning Plan for Coastal Areas and Small Islands.
- In the event that a change in the Spatial Plan, Detailed Spatial Plan for the Area, or the Zoning Plan for Coastal Areas and Small Islands cannot be made due to refusal by the Ministry of Forestry, then the matter shall be settled through the use of a holding zone.[17]
- Power infrastructure developments that utilise water, heat and wind, including transmission lines, are permitted in nature reserve areas and nature conservation areas.

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

2.4 Other relevant laws and regulations

2.4.1 Investment Law

Investment Law No. 25/2007 (the “2007 Investment Law”) is aimed at providing a one-stop investment framework for investors. This includes key investor guarantees such as the right freely to repatriate foreign currency, and key incentives such as exemptions from import duties and VAT otherwise due on imports of capital goods, machines or 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 social responsibility programme; and,
d) Meeting certain environmental conservation obligations.

The BKPM is given the power to coordinate the implementation of investment policy, including pursuant to the 2007 Investment Law.

Foreign investors wishing to participate in the power sector must first obtain a foreign investment licence from BKPM pursuant to the 2007 Investment Law. To do this, an Indonesian incorporated entity must be established and licensed as a PT PMA company (under the 2007 Investment Law and Company Law No. 40/2007). A PT PMA can be licensed for both the geothermal (i.e. the generation of steam) and power sectors.

Starting in 2015, once the PT PMA company is established it must apply through BKPM's one-stop service for an IUPTL licence and other licences (such as the permanent business licence and in-principle licence).

Refer to Section 2.2.4 – Authority to issue IUPTLs and other power-related licences and 2.3.5 - Ease of licensing for a detailed discussion of the licences issued by BKPM.

2.4.2 The Negative List

The “negative list” prescribes a set of business activities that are closed to foreign investment or that have limitations on foreign participation.

The most recent negative list detailed in PR No. 44/2016 prescribes foreign investment limitations in the power sector as follows:
a) Micro power plants (<1 MW) are closed for foreign investment;
b) Small power plants (1 – 10 MW) are open for foreign ownership up to a maximum of 49%;
c) Small geothermal power plants (≤ 10 MW) are now open for foreign ownership up to a maximum of 67%;
d) Power plants with a capacity of more than 10 MW are open for foreign ownership up to a maximum of 95% or 100% for PPP projects;
e) Electrical power T&D is open for foreign ownership up to a maximum of 95% or 100% for PPP projects;

f) Power supply construction and installation (including consultancy) projects and the Operation and Management ("O&M") of electrical power installations are open for foreign ownership up to a maximum of 95%;
g) High-/extra-high-voltage electrical power construction and utility installations are now open for foreign ownership up to a maximum of 49%;
h) Low-/medium-voltage electrical power construction and utility installations are closed for foreign investment;
i) Examination and testing of electrical power installations and high-/extra-high-voltage electrical power utility installations are now open for foreign ownership up to a maximum of 49%;
j) Examination and testing of electrical power installations and low-/medium-voltage electrical power utility installations are still closed for foreign investment; and,
k) Geothermal O&M services are open for foreign ownership up to a maximum of 90% and for drilling and surveying services up to a maximum of 95%.

2.4.3 The 2009 Environment Law

Pursuant to Law No. 32/2009, Minister of Environment Regulation No. 5/2012 on the Types of Businesses and/or Activities Required to Have an Analysis of Environmental Impact, IPP investors must comply with specific environmental practices and secure environmental permits before they begin operations as follows:

- Construction of transmission network – high-voltage air lines, high-voltage channel cables, high-voltage submarine cables > 150 kV.
- Construction of diesel, gas-fired, coal-fired, combined cycle power plants ≥ 100 MW in one location.
- Construction of geothermal power plants ≥ 55 MW.
- Construction of hydropower with the height of the weir ≥ 15 m or water pooling area ≥ 200 ha or the capacity of the power plant ≥ 50 MW.
- Construction of waste power plants with methane harvesting process ≥ 30 MW.
- Construction of other types of power plants (solar, wind, biomass) ≥ 10 MW (in one location).

Businesses and/or activities other that the above should have an environmental management/monitoring effort document (*Upaya Pengelolaan Lingkungan Hidup – Upaya Pemantauan Lingkungan Hidup*) or letter of intention of environmental management/monitoring.

2.4.4 Land Acquisition Law

The 2012 Land Acquisition Law and the Regulation on Land Procurement Procedures for Development and the Public Interest (PR No. 71/2012 and its amendments PR Nos. 40/2014, 99/2014 and 30/2015) aim to expedite the land acquisition process for certain infrastructure projects including power plants. The goal is to help overcome the difficulties encountered when compulsorily acquiring land for public purposes. The 2012 Land Acquisition Law and PR No. 71/2012 and its amendments repeal PR Nos. 36/2005, 65/2006 and 3/2007 and set out a maximum timeframe for the four stages of land acquisition, namely planning, preparation, implementation and the transfer of acquired land, and the sources of funding for land acquisition.

Power projects often face land acquisition issues. Before the instigation of this law, Indonesia did not have an established legal procedure for compulsorily acquiring land for public purposes. PR No. 71/2012 and its amendments also help overcome the obstacle of unregistered land by including holders of ‘customary land rights’ as being potentially eligible for compensation.

The maximum time period is set at 583 working days from the submission of the land acquisition plan to the issue of the certificate of registration including time for objections or appeals. An unwilling land owner can be forced to sell their rights for an amount of compensation approved by court review. Compensation may be in the form of money, replacement land, resettlement, stock ownership or other forms as agreed by the parties.

2.4.5 Bank Indonesia (“BI”) Regulation on the Obligation to Use Rupiah

BI Regulation No. 17/3/PBI/2015 on the Obligation to Use Rupiah for Transactions in Indonesia was effective as of 1 July 2015, with the stated aim of stabilising the Rupiah exchange rate.

The MoEMR issued a media release on 1 July 2015 (No. 40/SJI/2015) to outline the agreement between the MoEMR and BI concerning this regulation as it pertains to the oil & gas, mining and power industries following various discussions with the private sector. The media release refers to three categories of transaction as follows:

- Category 1: transactions that are able to be made directly in Rupiah, for example the lease of offices/houses/vehicles, salary payments for Indonesian employees and payments for various support services, where a transition period of up to six months will be given;
- Category 2: transactions where time is required to implement the provisions of the regulation, for example fuel purchases, import transactions through local agents, long-term contracts and multi-currency contracts, where transactions in fixed-term contracts shall continue to be in foreign currency with the possibility of future amendment;
- Category 3: transactions for which it is fundamentally difficult to fulfill the provisions of the regulation, for example salary payments for expatriates, drilling services and the lease of ships, where businesses may continue to use foreign currency.

Investors should continue to monitor this issue as further procedures for the implementation of the BI regulation are expected to be issued by the MoEMR and BI in due course.

We note that PLN is currently still paying invoices denominated in USD. However, for recently signed PPAs, despite the fact that the invoices will be denominated in USD, PLN will pay the invoice in IDR which will then be converted by SOE banks to USD when payment is transferred to the IPPs’ bank accounts. PLN has signed tripartite agreements with the SOE banks and IPPs to ensure that PLN does not violate the regulation requiring the use of IDR but at the same time does not violate the PPAs. However, there is a concern from the IPPs as to whether this arrangement will cover the entire term of the PPAs or only the period up to full repayment of the IPP’s loans denominated in USD.

2.4.6 BI Regulation on Foreign Currency Transactions

Based on BI Regulation No. 4/2/PBI/2002 and subsequent revisions including the latest revisions in Stipulation Letter No. 9/9/DSM dated 9 April 2007, non-financial institution companies with minimum assets of IDR 100 billion or annual gross sales greater than IDR 100 billion are required to report to BI foreign currency transactions made with:

a. Overseas banks or overseas financial organisations; and/or
b. Other companies or offices domiciled outside Indonesia.

Companies that have foreign currency financial assets and liabilities are also required to submit reports to BI.

The BI report consists of:

a. A monthly foreign exchange transaction report for all the company's financial assets and/ or liabilities in foreign currency (to be submitted within a month following the month in which the transaction occurs); and,
b. A half-yearly report on the foreign-currency financial assets and/or liabilities position at the end of the relevant period. The BI reports are used by the Government to prepare the Payment Statistics Balance Sheet and Indonesia's International Investment Position.

2.4.7 BI Regulation on 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 in Foreign Loan Administration for Non-bank Corporations includes a requirement for companies to report their foreign currency loans to BI on a quarterly basis. Further, the fourth quarter report needs to be verified by an independent public accountant. Failure to comply with the reporting obligations triggers administrative sanctions of IDR 10 million.

The prudential principles under BI Regulation No. 16/21/PBI/2014 and Circular Letter No. 16/24/DKEM as amended by Circular Letter No. 17/18/DKEM are as follows:

a. Minimum hedging ratio is 25% of the negative difference between current assets and current liabilities that will be due within three months and that will be due within three months and six months of the end of a quarter;
b. Minimum liquidity ratio is 70%, calculated by comparing the company's current assets and current liabilities that will be due within three months at the end of the reporting quarter;and,
c. Minimum credit rating of BB or equivalent from certain credit ratings agencies approved by the Indonesian Financial Services Authority.

3. IPP Investment in Indonesia

Photo source: PwC

3.1. History of IPPs in Indonesia and the PPP framework

Unlike the oil and gas and mining sectors, power investment has generally not (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, particularly PPAs.

IPPs have existed in Indonesia pursuant to PPAs since the early 1990s and are classified into three broad generations (as outlined below). IPPs currently account for approximately 21% of Indonesia's total generation capacity of 55.5 GW. Certain IPPs, particularly in recent times, have also operated pursuant to a more general set of PPP arrangements.

The key regulation governing the 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 contains general guidelines for PPP implementation.

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 forecast returns (Internal Rate of Return (IRRs) often between 20% and 25%) together with the provision of a Government guarantee (via a support letter to cover PLN's obligations under the PPA) meant that there was initially a high investor uptake during IPP tendering.

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. Ultimately six projects were terminated, six were acquired by the Government, one project ended up in a protracted legal dispute, and 14 projects continued under renegotiated terms. When renegotiations were completed in 2003 most continuing IPP investors agreed to new PPAs, which generally included lower tariffs than were initially contemplated.

Nevertheless, this first generation saw generating capacity lifted to 4,262 MW. Landmark projects included the Salak Geothermal Plant (albeit under a Joint Operation Cooperation – "JOC" framework), the Cikarang Combined Cycle Plant and the coal-fired Paiton Plant (Paiton I). Paiton I was the largest of those IPP projects with installed capacity of 2 x 615 MW.

During 1999 - 2004 there were however no projects tendered.

3.2.2 Second generation (Asian financial crisis to 2009)

The second generation of IPPs commenced during the period 2005-2009. This generation was however not viewed as particularly attractive to investors as:

a) No Government guarantees were provided. Rather than provide direct government

support to IPP projects, the MoF entered into the Japan Bank for International Cooperation ("JBIC") Umbrella Note of Mutual Understanding for projects (such as Marubeni's Cirebon Plant) benefiting from JBIC export credit support;
b) The risk allocation was not viewed as favourable to investors; and
c) The forecast returns were lower (with forecast IRRs often 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 third-generation IPP projects are PPP projects, FTP II projects, 35 GW programme projects and IPP projects under PLN's regular programme. Third-generation IPPs that operate as PPPs fall under 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 the investor. 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 around the existing PPP framework. The key enhancements under PR No. 38/2015 are:
a) The sectors covered are wider and now include oil & 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 is permitted (the projects need to be procured together, e.g. a power plant and related import infrastructure);
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" (to be further defined by the MoF) is available;
f) Projects to be developed through unsolicited bids are encouraged by providing compensation to the proponent of:
   i) An additional 10% price preference in bid evaluation;
   ii) The right to match a lower price bid by a competitor;
   iii) The purchase of the 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 continues to be available via the Business Viability Guarantee Letter and any separately available tax incentives;
h) A Government guarantee to cover the GCA's financial obligations is provided;
i) The cost of preparing a project can include a retainer, fixed fees and success fees. The Government's project preparation costs can be recovered from the winning bidder and can include costs for:

    i) The pre-feasibility study;
    ii) Managing the transaction;
    iii) Compensation to international organisations/consultants in assisting project preparation 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 first PPP in the power sector was the Central Java Power Plant (CJPP) with a capacity of 2 x 1,000 MW and an estimated investment of USD4.2 billion. The CJPP will operate under a Build, Own and Transfer ("BOT") structure and 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 issued in October 2011. The land acquisition process for this project was completed in late 2015 and the financial closing for this project has been completed in June 2016. The construction of the power plant is ongoing with expected COD by 2020.

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 launched under MoEMR Regulation No. 15/2010 and revised most recently by the new Minister for Energy, Mining and Resources, Sudirman Said, on 31 December 2014 in MoEMR Regulation No. 40/2014 to 17.4 GW, focuses on the use of IPPs and the use of coal and renewable sources of energy such as geothermal and hydro. The new five-year 35 GW programme announced by President Joko Widodo has superseded FTP II and all projects planned for completion between 2015 and 2019 have been rolled into the 35 GW programme.

The 35 GW programme (2015 - 2019)

A five-year 35 GW programme was announced by President Joko Widodo in late 2014. The goal is to complete 35 GW of power generation projects by the end of his first term. An additional 46,000 km of transmission lines is also planned.

These projects may be awarded through open tender, direct appointment or direct selection (see Section 3.4 "Procurement process"). Based on PR No. 4/2016, they are also eligible for the MoF's business viability guarantee. Further details on the procedures and provisions for the guarantee will be regulated by a MoF Regulation that has not yet been issued.

For further detailed discussions, please see Section 3.8.2 "The 35 GW power development programme".

PLN's regular programme

PLN's regular programme includes PLN projects, IPP projects and unallocated projects planned for completion after 2019 that can be found in PLN's RUPTL. IPP projects are subject to the same regulations as the 35 GW 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: Guidelines for PPP implementation. • PR No. 78/2010: infrastructure guarantees for PPPs provided through IIGF. • MoF Regulation No. 260/2010, (as amended by MoF Regulation No. 8/2016): implementing guidelines for infrastructure guarantees in PPPs.	• Guarantee is provided to the IPP and covers the contracting agency's/ Government's financial obligations as stated in the PPA. • Guarantor is the IIGF, sometimes jointly with the GoI.	• Central Java 2 x 1,000 MW coal-fired plant
IPP FTP II (superseded by 35 GW program)	• PR No. 4/2010 amended by PR No. 194/2014, revised and MoEMR Regulation Nos. 21/2013, 32/2014 and 40/2014: the list of projects to accelerate the construction of renewable energy-, coal- and gas-fueled power plants. • Bidding process follows MoEMR Regulation No. 1/2006 and its revisions under MoEMR Regulations Nos. 4/2007 and 3/2015. MoF Regulation No. 173/2014: government guarantee for IPPs and PLN obligations to IPPs to purchase power in accordance with the PPA.	• Business Viability Guarantee Letter from MoF provided to existing IPP projects covering PLN's financial viability. Based on PR No. 4/2016, 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 • Wampu 1 x 45 MW hydro power plant, North Sumatra

	Regulations	Guarantees	Examples
35 GW programme	• PR No. 4/2016 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 (see Appendix A for a list of projects). • Bidding process follows MoEMR Regulation No. 1/2006 and its revisions under MoEMR Regulations Nos. 4/2007 and 3/2015. • GR No. 14/2012 (as amended by GR No. 23/2014) and MoEMR Regulation No. 3/2015 permit the direct selection and direct appointment of an IPP in some circumstances. • MoEMR Regulation No. 3/2015 sets the feed-in tariffs for certain feedstocks. • Under MoEMR Regulation No. 35/2014 BKPM provides a one-stop service for permits and licensing.	• Based on PR No. 4/2016, 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.	• Riau Kemitraan 2 x 600 MW coal-fired power plant (Sumatra) • Jambi 2 x 600 MW coal-fired power plant (Sumatra) • 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, 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.	• Various large-scale coal-fired plants, hydropower and geothermal plants on Java, Sumatra and Kalimantan listed in the RUPTL for completion after 2019.

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 providing guarantees to PPP projects from the IIGF. Its aim is to accelerate the development of infrastructure projects by reducing the risk of financing for infrastructure investors (including IPPs), by essentially providing sovereign "guarantees" or "letters of comfort" for a fee. The IIGF essentially functions as an insurer of any risk exposure of the private sector for a premium. The IIGF is increasing its guarantee capacity through cooperation with multilateral agencies and bilateral institutions.

As indicated above, in October 2011 the USD4.2 billion CJPP was the first PPP to receive an IIGF guarantee, which was in the form of a joint guarantee facility from the IIGF and the MoF. The IIGF has since initiated processes for the South Sumatra coal-fired mine-mouth power plants 9 (consisting of 2 x 600 MW of capacity) and 10 (1 x 600 MW).

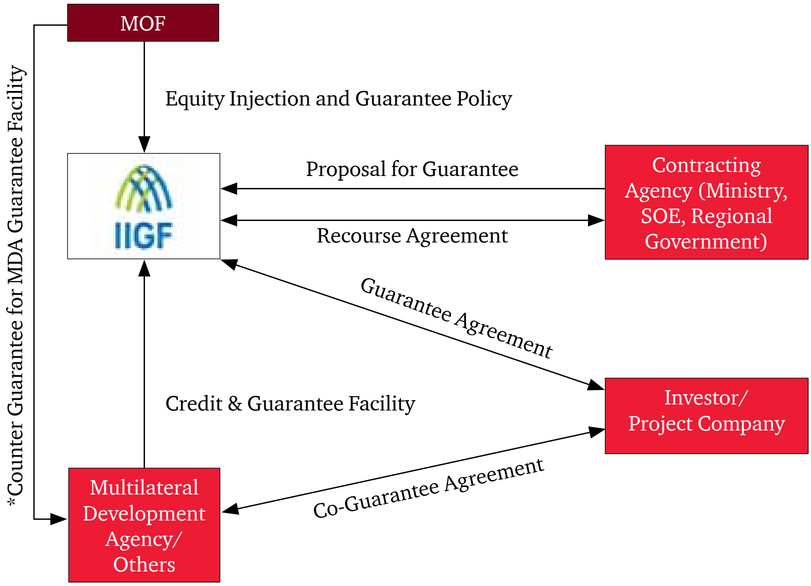
The IIGF will function as a "single window" for all requests for Government guarantees on PPP projects with the following objectives:

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 risk by ring-fencing Government obligations against guarantees.

The issuer of the Guarantee Agreement is the IIGF but it could also operate with Multilateral Development Agency or MoF support. The guarantee covers the financial obligations of the contracting agency (PLN for electricity) and the addressee is generally the project company (IPP investors for electricity).

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

The overall guarantee arrangement is outlined in the following diagram:



Source: PTPII's 2014 Annual Report

* Counter Guarantee for Multilateral Development Agency ("MDA") 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 to fund some relevant construction costs and/or in other forms 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 and the guidelines for application and disbursement are contained 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 the proposal by the Minister/Chairman of Governmental Institution responsible for certain Infrastructure Projects (Transportation, Road, Water, Irrigation, Wastewater, Telecommunication, Electricity and Oil and Gas)/Head of Region (Governor or Regent). This is available only if there is no practical means of making an economically feasible project financially viable. Examples include toll road construction projects outside Java or water supply projects with a higher social rather than commercial element. Power projects are not usually eligible as most 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 covering 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 covered. The guarantee will terminate if the IPP fails to achieve financial close within 12 months of its issuance (24 months in the case of geothermal projects).

Based on PR No. 4/2016, FTP II programme projects that are rolled into the 35 GW programme, and other 35 GW projects, are also eligible for MoF's business viability guarantee. Further details of the procedures and provisions for the guarantee will be regulated by a MoF Regulation that has not yet been issued. 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 was established to help investors obtain domestic finance for the debt and equity funding of infrastructure developments including power projects.

PT IIF provides long-term loans, mezzanine and equity investment as well as guarantees and fee-based services for infrastructure projects.

PT SMI and PT IIF contribute to the acceleration of infrastructure development through advisory services such as project feasibility studies and financing schemes; providing advice to the GoI on forms of incentives, fiscal policy support and regulatory reform; and socialisation through Investor and Infrastructure Forums.

In addition, in 2015, PT SMI was assigned by the Government to manage the Geothermal Fund. For further details, please refer to Section 5.2.1 - The 2014 Geothermal Law.

3.4 Procurement process

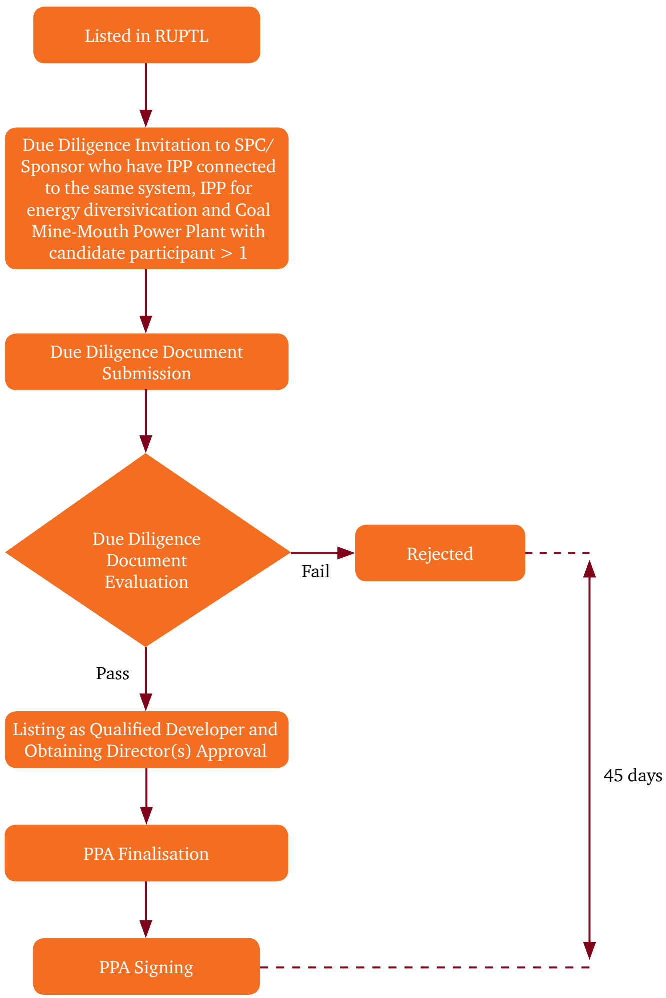
Investors can participate in power generation projects via PPP arrangements, the 35 GW programme or PLN's regular programme. The procurement process for new capacity is generally run on a competitive tender basis (MoEMR Regulation No. 1/2006, which was amended by MoEMR Regulation No. 4/2007) although GR No. 14/2012 (as amended by No. 23/2014) and most recently MoEMR Regulation No. 3/2015 allows the direct selection and direct appointment of an IPP for projects in the following circumstances:

a) Direct selection is permitted when changing the feedstock of the power plant from diesel to non-diesel and/or adding to the capacity of an existing power plant, not in the same location;
b) Direct appointment is permitted for the following:

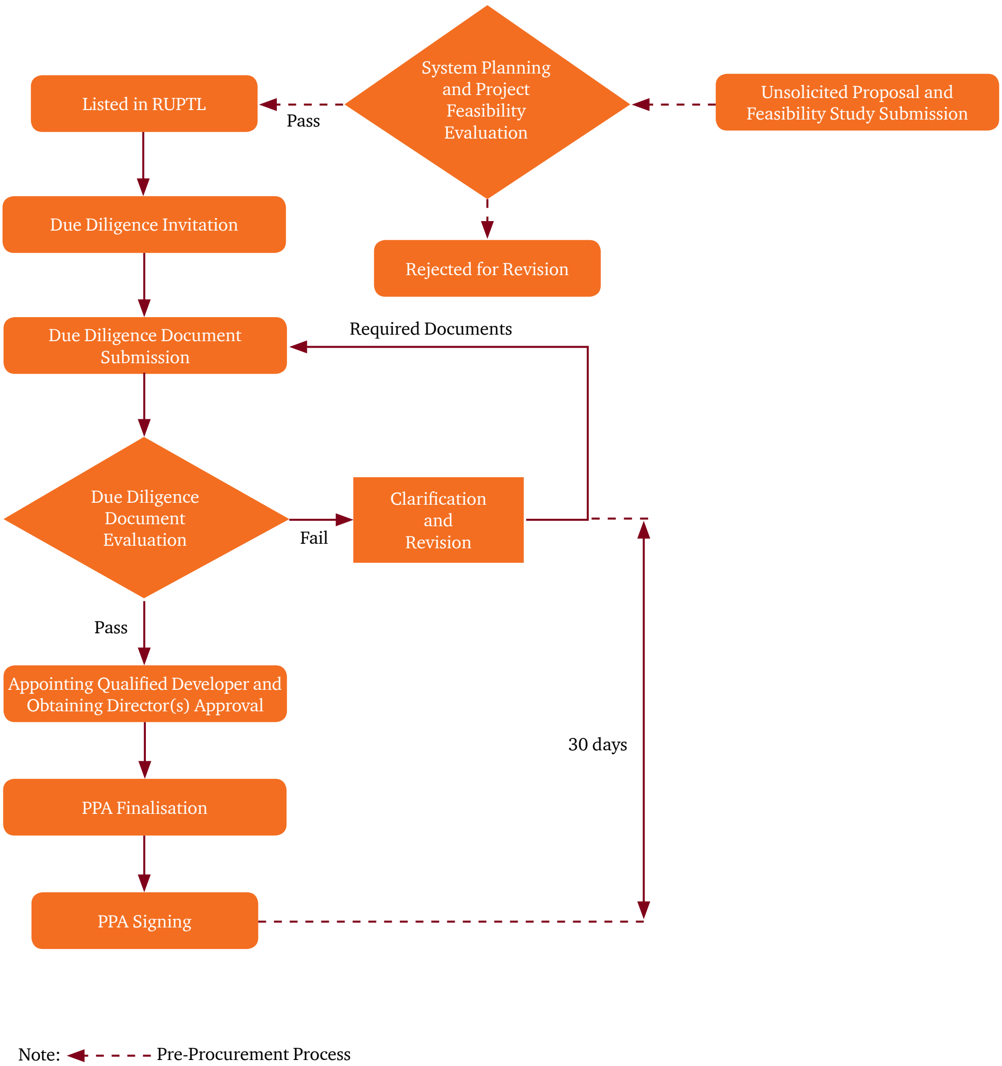
i) Mine-mouth, marginal gas and hydropower projects;
ii) The purchase of excess power supply from mine-mouth, coal-fired, gas-fired/gas-machine and hydropower plants;
iii) The purchase of electricity from mine-mouth, coal-fired, gas-fired/gas-machine and hydropower plants for critical or emergency power supply; and,
iv) Expansion projects at the same location.

According to MoEMR Regulation No. 3/2015, further procurement procedures for direct selection and direct appointment will be determined by PLN. The maximum time-frame for the execution of the PPA is 30 days for direct appointment and 45 days for direct selection.

Procurement procedures for direct selection which comply with MoEMR Regulation No. 3/2015 are as follows:



Procurement procedures for direct appointment which comply with MoEMR Regulation No. 3/2015 are as follows:



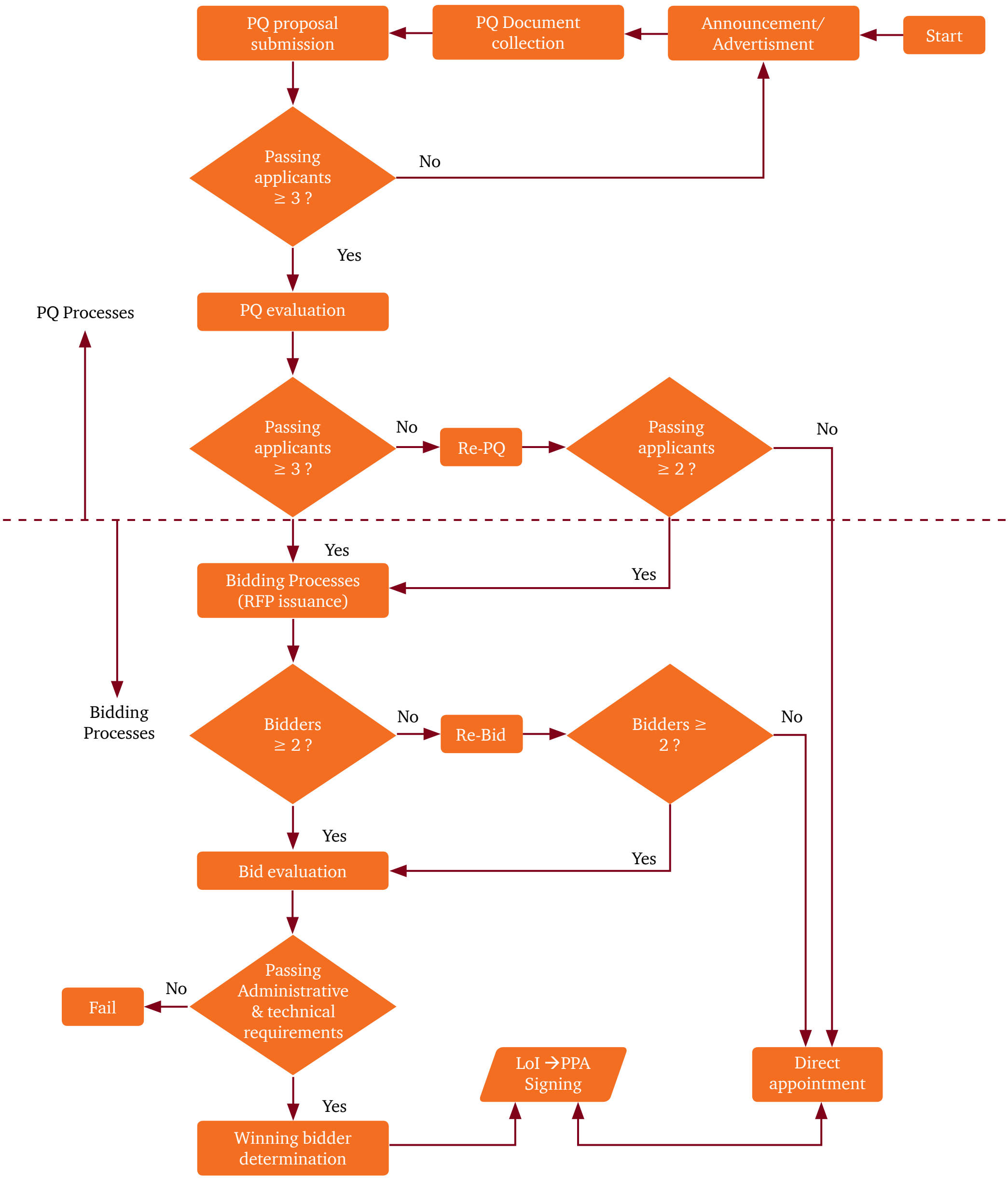
Competitive tendering for a project follows a process as set out in MoEMR Regulation No. 1/2006 and its revision under MoEMR Regulation No. 4/2007. PPP projects have specific regulations (PR No. 38/2015) that are broadly similar to the MoEMR regulations.

The regulations state that:
a) The tenders are to be based on the RUPTL;
b) The evaluation and pre-qualification phase is to be based on financial strength and technical capabilities;
c) The requests for proposals are to include a model PPA and the evaluation procedure; and,
d) The selection process should identify the best bid based upon:
   i) Administrative and technical parameters;
   ii) The electricity price proposal; and,
   iii) The development/construction schedule.

The electricity price will be based on negotiation and/or the applicable FiT regulations for geothermal and some other renewable energy plants (see Chapter 5) for direct appointment and on the lowest price proposal submitted by the participants for direct selection or open tender.

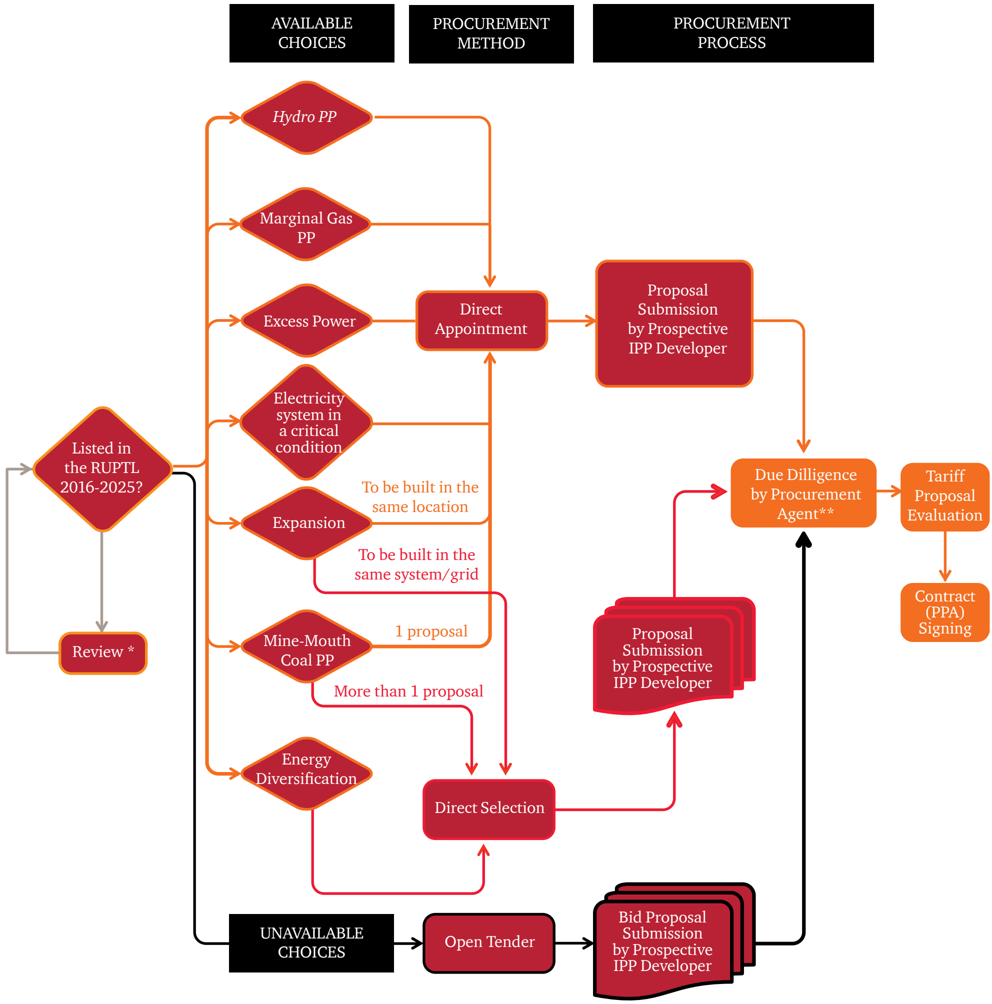
After the preferred bidder is selected, the process from award of tender to operation will involve the following:
a) The issue of a Letter of Intent that contains the agreed terms and conditions and the agreed electricity tariff and basic formula;
b) The signing of the PPA, which requires a performance bond covering the financing period, PLN's corporate approval, MoEMR tariff approval and the establishment of a special-purpose company with a temporary business licence applied for from BKPM's one-stop service);
c) Financial close, which requires the EPC Contract, insurance policies required by the PPA, the fuel supply plan, financial agreements, foreign investment approval, the legal opinion issued for PLN, the legal opinion issued for the IPP, legal rights to use the land and control over the site and a performance bond covering the construction period;
d) The commencement of commercial operations, which requires that the net dependable capacity test procedures be completed.

Procurement procedures for competitive tenders as set out in MoEMR Regulation No. 1/2006 and the revision thereof based on MoEMR Regulation No. 4/2007 are as follows:



Note: PQ = Pre-qualification, RFP = Request For Proposal

The flowchart below describes the relationships between the various types of power plants and the procurement process:



Note:

* Mid programme evaluation after > 2 years

** Financial and technical evaluation

- The IPP procurement process will be conducted by procurement committee of PLN or procurement agent
- This table is adapted from MoEMR Regulation No. 03/2015

Source: PLN

3.5 Project finance

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 exploration to decide whether the project is viable, including a feasibility study to decide whether the project is bankable. A financial advisor may be appointed at or near completion of the feasibility study;
b) The financial advisor assists in preparing a request for proposal 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, credit committees specify 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, servicing debt and generating returns for the investors.

The main sources of project finance for Indonesian IPPs have been:
a) International commercial banks;
b) Multilateral Development Agencies (“MDAs”) such as regional multilateral banks (e.g. ADB and 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. Financing through local banks is rare, as the liquidity of domestic banks for long-term structured financing is limited.

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) O&M agreements; and
f) Financing documents.

These are further discussed in the table below.

Key Project Contracts	Contracting Parties	Purpose of Contract
Shareholders' Agreement	Shareholders in the project's special-purpose vehicle - generally the IPP entity)	Provides for the rights and obligations of shareholders
Shareholders' Loan Agreement	Shareholders in the IPP entity	Covers terms and conditions for any shareholder's loans
PPA	IPP entity and PLN	Sets out terms and conditions of power generation activity
EPC Agreement – Offshore	IPP entity and third party contractor and/or affiliates	Sets out terms and conditions for supply of offshore design and construction work
EPC Agreement – Onshore	IPP entity and third party contractor and/or affiliates	Sets out terms and conditions for the supply of local construction services
EPC Wrap Agreement (also known as Umbrella or Guarantee & Coordination Agreement)	IPP and contractors	Guarantees the performance of the offshore and onshore contractors jointly
Long-Term Fuel Supply Agreement	IPP and third party (generally)	Governs the availability of long-term fuel supply
O&M Agreement	IPP and O&M contractor	Governs O&M services and associated fees and overheads
Technical Services Agreement	IPP and affiliates/third parties	Governs the provision of technical services to the IPP entity

Key Project Contracts	Contracting Parties	Purpose of Contract
Project Finance Documents	Financiers and IPP	To cover the key aspects of project financing including for: • Corporate Lending • Export Credit Agencies • Cash Waterfall • Hedging • Political Risk Guarantees • Intercreditor Agreements • Security Documents; • Sponsor Agreements
Developers'/Sponsors' Agreement	Sponsor and IPP	To provide a developer's fee paid by the IPP entity to the original sponsors

3.6.1 General terms of a PPA

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

a) The objective and scope of the contractual work or service (i.e. as either a Build, Own and Operate ("BOO") or BOT);
b) The period of operation (coal PPAs are generally for 25 years, hydro 30 years, geothermal 30 years and gas 20 years);
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) Tariff and payment;
i) Government guarantees (if applicable);
j) Service performance standards;
k) Insurance arrangements;
l) Indemnification and liability arrangements;
m) *Force majeure* scenarios (natural and political);
n) Settlement 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 The 2016 RUPTL – greater role of private sector

As discussed in Chapter 1, Indonesia's economic fundamentals and its emerging regulatory framework have combined to encourage renewed investor optimism within the power sector. The 2016 RUPTL aims to achieve an electrification ratio for Indonesia of 99.7% by 2025. To achieve this level of electrification, the 2016 RUPTL indicates that at least 80.5 GW of power plants will need to be constructed by 2025, with 18.2 GW of plants planned to be constructed by PLN and 45.7 GW by IPPs. The remaining 16.6 GW has not yet been allocated between PLN and IPPs. To build these levels of power generation, PLN and IPPs will be required to invest at least USD31.9 billion and USD78.2 billion, respectively. As such, for the next ten years, the private sector will play a greater role than ever in the Indonesian power sector. In addition, PLN will also be required to make additional investments of around USD43.7 billion for transmission and distribution networks.

Based on the 2016 RUPTL, IPPs may have access to power generation projects as follows:

	PLN	IPPs	Unallocated	Total
Coal	7,962	25,125	1,714	**34,801**
Geothermal	400	5,060	690	**6,150**
Gas/Combined Cycle	7,096	6,780	9,310	**23,186**
Hydro (including mini-hydro and pumped storage)	2,749	6,787	4,929	**14,465**
Other	15	1,922	-	**1,937**
Total	**18,222**	**45,674**	**16,643**	**80,539**

The 2016 RUPTL is focused on achieving the 23% energy mix from renewables as dictated by the 2014 NEP. Given the current low levels of power generation from renewables, achieving the 23% target by 2025 means that the renewable power generation in the 2016 RUPTL should represent at least 25% of the fuel mix by 2025. Based on the 2016 RUPTL, after optimising all the renewable potential, the projected fuel mix from renewables will increase from only 11% in 2016 to 19% in 2025. As such, the utilisation of an additional 5 GW of gas-fired generation is required as a contingency plan if the renewables target cannot be met (although this additional gas generation is not included in the 80.5 GW target). The projected composition, by primary energy source, of electricity production in Indonesia by 2025 is planned to be: 50.3% from coal; 29.4% from gas (including LNG); 8% from geothermal; 10.4% from hydro; 0.6% from diesel fuel; and the remaining 1.3% from other fuels (see Figure 1.7). This is consistent with the draft 2015 – 2034 RUKN which requires a fuel mix of approximately 50% from coal, 24% from gas, 25% from renewables and 1% from diesel fuel.

Coal will continue to play a vital role in the development of power generation in Indonesia for the next ten years due to the relatively lower costs of construction and operation. Coal mine-mouth power plants remain integral to the plan, 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 more environmentally friendly technology (lower carbon) such as supercritical and ultra-supercritical boilers is a key priority for PLN and the Government in the development of large scale coal-fired power plants, particularly on the highly populated Java Island. The use of other types of technology, such as integrated combined cycle gasification and carbon capture & storage have not yet been planned for in the 2016 RUPTL.

PLN also plans for the extensive use of LNG for gas-fired power plants. However, because of the relatively higher cost of LNG (compared to pipeline gas) given the need for regasification, PLN plans to use LNG as a peak-load back-up rather than for base-load power plants, particularly for the Java-Bali, Sumatera and eastern Indonesia networks, where base-load generation may not be sufficient.

In addition, there are significant opportunities for private investors in captive power / Private Power Utilities ("PPU"). PPUs are gaining attention in the market as they can significantly reduce the risk of blackouts to firms, avoid revenue losses, and reduce overtime and diesel genset costs. In a recent study, we estimate a pipeline of Industrial Estate demand of 8-10 GW by 2019.[18] While most of this will be supplied by on-grid plants in the table above, a portion is likely to be supplied from off-grid or grid-connected PPUs.

3.7.2 The 35 GW power development programme

The 2016 RUPTL indicates some changes in the 35 GW programme launched in 2015, whereby the initial 35 GW programme (which actually targeted 36.5 GW of power generation) has been reduced to 35.6 GW. Coal and gas-fired generation has been reduced by approximately 400 MW and 700 MW, respectively, while renewables have been increased by 300 MW (hydro reduced by 300 MW and geothermal increased by 600 MW). This is consistent with the NEP discussed above.

Initial 35 GW Programme

Development Scheme	Coal	Gas	Hydro	Geothermal	Other	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**

35 GW Programme - 2016 RUPTL

Development Scheme	Coal	Gas	Hydro	Geothermal	Other	Total (GW)
PLN	2.2	6.8	1.4	0.2	-	**10.6**
IPP	17.6	6.1	0.6	0.5	0.2	**25.0**
Total (GW)	**19.8**	**12.9**	**2.0**	**0.7**	**0.2**	**35.6**

18 PwC and GE (2016), *op.cit.*, p. 13

Please note that the 35 GW programme continues to evolve due to more accurate assessments made by PLN and the Government for the size of each power plant. As such, there is a discrepancy with the total size of this 35 GW programme as discussed above. In PLN's 2015 Annual Report, the size of the 35 GW programme is 35,528 MW,[19] in the 2016 RUPTL it is 35,627 MW, and in Table 3.1 (based on other information from PLN) it is 36,054 MW. Based on the 2016 RUPTL, the discrepancy was mainly due to the cancellation of projects and the change in the size of projects. Please note that different sources indicate that the size of the 35 GW programme is actually between 35 and 37 GW and may be subject to further change.

Table 3.1 - Planned Power Projects and Construction of T&D 2015-2019

Scope	Capacity
Generation	36,054 MW
Transmission	42,159 km

Source: PLN (The Jakarta Post, 13 July 2016, "The Mega Electricity Project will still rely on fossil fuels").

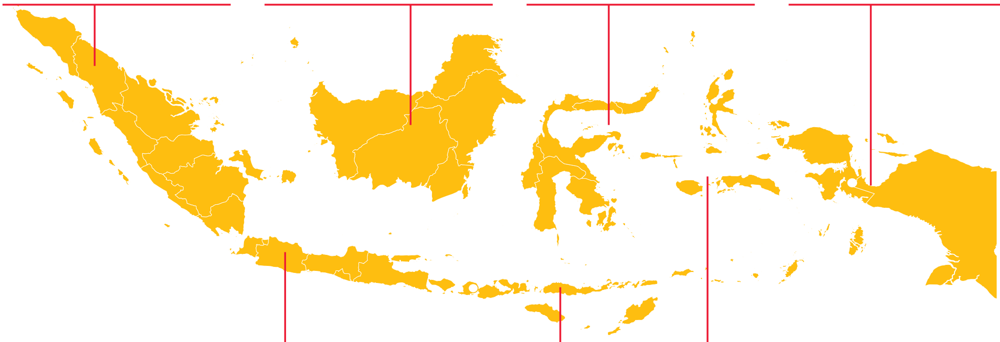
The location of the planned power projects and transmission lines and distribution networks for the period 2015 - 2019 as well as total investments required are as follows:

Sumatera	
Power plant: - PLN - IPP	 1,100 MW 8,990 MW
Transmisssion line	18,729 km

Kalimantan	
Power plant: - PLN - IPP	 900 MW 1,735 MW
Transmisssion line	5,604 km

Sulawesi	
Power plant: - PLN - IPP	 2,000 MW 1,470 MW
Transmisssion line	5,276 km

Papua	
Power plant: - PLN - IPP	 220 MW 0 MW
Transmisssion line	364 km



Java	
Power plant: - PLN - IPP	 5,000 MW 13,697 MW
Transmisssion line	9,186 km

Nusa Tenggara	
Power plant: - PLN - IPP	 670 MW 0 MW
Transmisssion line	2,347 km

Maluku	
Power plant: - PLN - IPP	 260 MW 12 MW
Transmisssion line	653 km

Source: PLN (The Jakarta Post (13 July 2016)).

19 2015 PLN's Annual Report p. 10

The 35 GW programme appears to be progressing, albeit slower than hoped. The full list of 35 GW projects is included in Appendix A, but in summary, as of 29 June 2016:[20]

- 1% (170 MW) of capacity had reached the Commercial Operations Date;
- 22% (8,150MV) of capacity was in the construction stage;
- 26% (9,680 MW) of capacity had PPAs signed, but had not yet commenced construction;
- 22% (8,080 MW) of capacity was still in the planning stage;
- 29% (10,605 MW) was in the procurement stage.[21]

The causes of delay are well known and key risks identified by IPPs include land acquisition difficulties (for the generation site and transmission corridor), infrastructure to transport feedstock to plants (e.g. gas, biomass), the speed of IPP/PPP procurement, the speed of licence and permit acquisition (especially at sub-national level) and gaps in the regulatory framework (including a lack of FiT for some technologies and lack of sovereign guarantees for IPP debt). These issues are discussed in more detail in the following chapters.

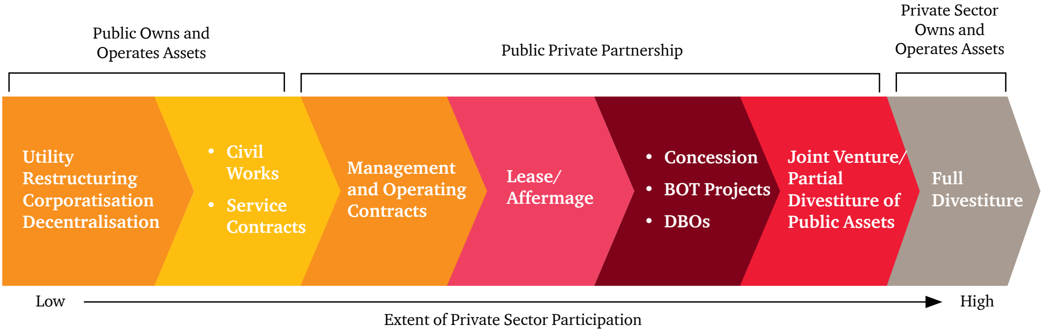
However, we note that the Government well recognises these risks to the programme and has implemented eight Acceleration Steps, including in relation to land acquisitions for power generation, T&D, tariff negotiation, IPP procurement, permits, IPP developer and EPC due diligence, project management capacity, inter-ministerial coordination and legal issues. Furthermore, President Widodo also approved PR No. 4/2016 in January 2016 which aims to address the challenges specific to the 35 GW programme. Under the Presidential Regulation, a special mandate has been granted to PLN in the form of a sovereign guarantee, expedited permit process, and preparation of land under the spatial plan. For further details on PR No. 4/2016, please see Section 2.3.

3.7.3 PPPs

Currently, there is 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 varying in the extent of involvement of and risks taken by the private party. The terms of a PPP are typically set out in a contract or agreement to outline the responsibilities of each party and clearly allocate risk. The graph below depicts the spectrum of PPP agreements.[22]

20 Please note that there are discrepancies in data from different sources, as discussed above. As such, the information should be used as an indication only.
21 http://finance.detik.com/read/2016/06/29/193735/3245300/1034/realisasi-proyek-35000-mw-per-hari-ini accessed 2 July 2016.
22 http://ppp.worldbank.org/public-private-partnership/overview/what-are-public-private-partnerships accessed 22 May 2016.



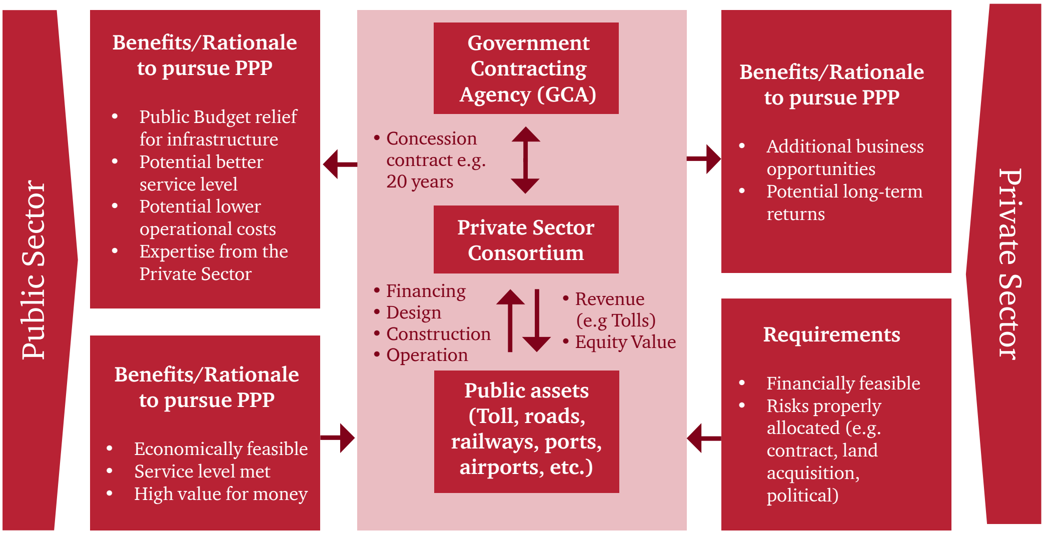
Source: World Bank

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

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

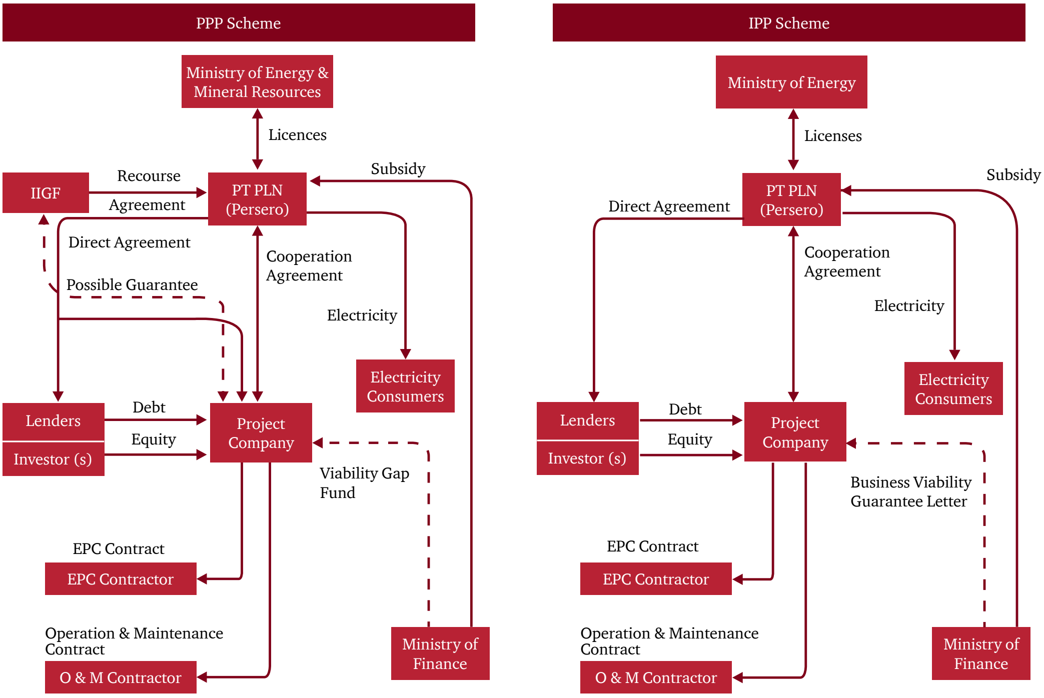
As discussed in Chapter 1 and this chapter, Indonesia is building a significant amount of infrastructure, which requires an enormous amount of investment that the Government cannot afford. As such, PPP is one of the possible ways to develop Indonesia's infrastructure. However, the term PPP in the Indonesian context is slightly different from that in the global context according to the definition of 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 a PPP in Indonesia where it does not fall under the scope of the PPP regulation (PR No. 38/2015) since an IPP does not have any guarantee from 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 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 are met. The Government requires that the projects provide the public with a high-quality service and the investors require that the projects be financially feasible and that the risks be manageable, including contract, 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 partnership with the private sector is allocated only for generation, whereby 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)

The Government has highlighted several power projects in the Bappenas "Public-Private Partnerships: Infrastructure Projects Plan in Indonesia" report (the PPP Handbook 2013 and 2015). They are:

1) The Central Java Coal-Fired Power Plant (2 x 1,000 MW). The PPA has been signed. Land acquisition has been completed and the construction of the power plant is ongoing.
2) The South Sumatra 9 (Sumsel 9) Mine-Mouth Coal-Fired Power Plant (2 x 600 MW). The project is in the process of obtaining in-principle approval of guarantees from the IIGF and the MoF.
3) The South Sumatra 10 (Sumsel 10) Mine-Mouth Coal-Fired Power Plant (1 x 600 MW). The project is in the process of obtaining in-principle approval of guarantees from IIGF and the MoF.
4) The Karama Hydropower Plant (4 x 112.5 MW), a prospective project.
5) The Tebo Mine-Mouth Coal-Fired Steam Power Plant (2 x 200 MW), a potential project.

The tenders of Sumsel 9 and 10 constitute the next major PPP projects in the power sector since the signing of the CJPP PPA in 2011. A guarantee is expected to be provided by the IIGF under the PPP framework as detailed in PR No. 67/2005 (most recently amended by PR No.66/2013). The guarantee arrangement is based on an assessment by the IIGF. The tender is competitive and was initiated through preliminary market sounding in October 2012. The bid deadlines for the Sumsel 9 and 10 tenders have been repeatedly extended since 2015. As discussed in Section 1.4 - Transmission and distribution ("T&D"), if the HVDC project is delayed or cancelled the Sumsel 8, 9 and 10 power generation projects totaling 3,000 MW are also likely to be cancelled or delayed too.

3.7.4 Other challenges

Although the Government has made positive inroads into alleviating investor concerns in relation to investment in IPPs, a number of challenges remain, including:

a) Difficulty in obtaining licences from Government ministries and departments, such as Local Government, Environment and Forestry, not currently part of BKPM's one-stop service;
b) Land acquisition including local community objections;
c) Financing issues including uncertainty around the availability of Government guarantees; and,
d) The lack of transmission lines and, to a lesser extent, other supporting infrastructure.

The Government is well aware of these issues and issued PR No.4/2016 in January 2016 to support PLN, its subsidiaries and IPPs in relation to the acceleration of the electricity infrastructure development programme for the 35 GW power plants and transmission network of 46,000 km. Please refer to Section 2.3 for a discussion of PR No. 4/2016.

4. Conventional Energy

Photo source: PT Paiton Energy

4.1 Introduction

Global primary energy consumption increased by just 1.0% in 2015, below the growth recorded in 2014 of 1.1% and well below the ten year average of 1.9%. This represented the lowest global growth since 1998, except the recession of 2009. Oil remained the world's leading fuel, accounting for 32.9% of global energy consumption. Globally, natural gas and coal accounted for 23.8% and 29.2% of primary energy consumption, respectively.[23]

Indonesia's primary energy supply has increased by 52.4% from 1,144.5 million barrels of oil equivalent ("MBOE") in 2004 to 1,745.1 MBOE in 2014. Coal and oil remained Indonesia's leading sources of energy supply, accounting for 28.5% and 28.1% of Indonesia primary energy supply, respectively. Biomass and biofuel represented a further 22.9%, followed by natural gas of 17.4%. Hydro accounted for 2.2%, with the remaining 0.9% from geothermal.[24]

Indonesia's final energy consumption has increased by 63% from 603.9 MBOE in 2004 to 982.8 MBOE in 2014. Fuel, coal and natural gas accounted for 40.3%, 22.5% and 12.7% of final energy consumption, respectively. The remaining consumption was electricity, LPG and others accounting for 12.4%, 5.3% and 6.8% respectively.[25]

Overall, conventional energy (coal, oil, gas) has continued to play a dominant role in Indonesia's energy mix.

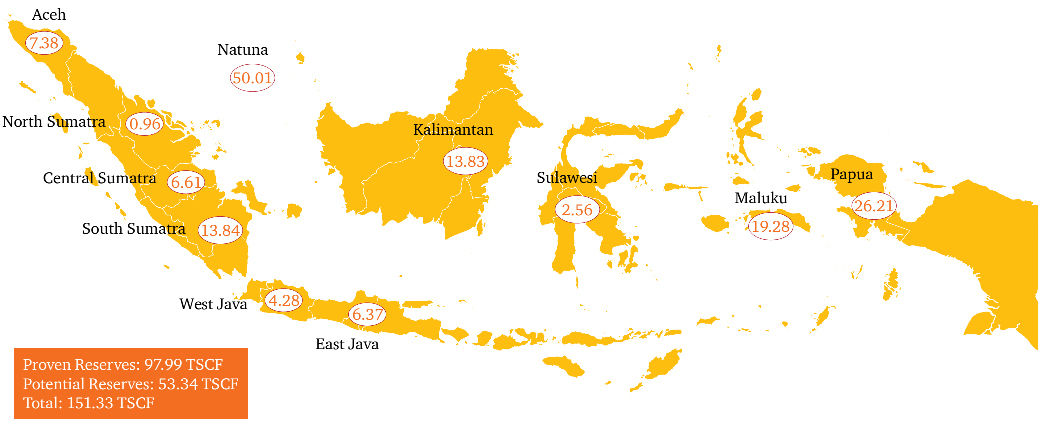
4.2 Gas

4.2.1 Indonesian gas reserves, consumption, and production

Indonesia has large natural gas reserves, at around 151.33 trillion standard cubic feet ("TSCF") in 2015 (see Figure 4.1 below for more details).[26] From proven reserves of 97.99 TSCF, only 33 TSCF are held by operating working areas, with the remainder not yet produced.[27] The largest undeveloped gas reserves are located in the offshore East Natuna Block, which holds approximately 46 TSCF of gas reserves. Other potential areas are West Papua and Sulawesi.[28] However, assuming there is no discovery of new reserves, and at current rates of consumption, reserves could run out in 34 years.[29]

23 BP Statistical Review of World Energy June 2016, p. 2 and 4.
24 2015 Handbook of Energy and Economic Statistics of Indonesia, p. 17.
25 *Ibid*., p. 25.
26 *Direktorat Jenderal Minyak dan Gas Bumi, Laporan Kinerja 2015, ("LAKIP DJMGB 2015"), Februari 2016* [Directorate General Oil and Gas, 2015 Performance Report February 2016], p. 42.
27 *SKK Migas, Laporan Tahunan 2015* [SKK Migas, 2015 Annual Report], p. 21.
28 International Energy Agency ("IEA"), Indonesia 2015, 2015, p. 42.
29 Badan Pengkajian dan Penerapan Teknologi (BPPT), Indonesia Energy Outlook 2015, p. 15.

Figure 4.1 Map of Indonesian Gas Reserves as of 1 January 2015 (in TSCF)



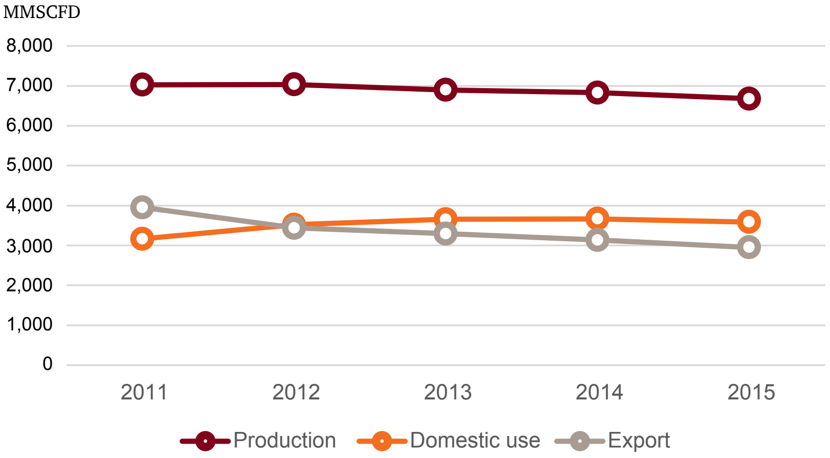
Source: LAKIP DJMGB 2015

Despite the fact that crude oil has traditionally played a greater role in Indonesia's energy supply and exports, Indonesia is now a net oil importer. In terms of calorific value, natural gas production surpassed that of crude oil in 2012. This situation has also resulted in the Government's shifting focus from oil to natural gas.[30] Production of natural gas on average is 60% of total production of oil and gas as a whole and it is expected that it will reach 70% in 2020 and 86% in 2050.[31]

Indonesia has experienced a gradually narrowing surplus of gas production over domestic consumption for the past five years (see Figure 4.2). Indonesia's gas industry under pressure due to declines in the oil and gas price, fundamentally changing the economics of development of oil and gas fields or delays in these developments reaching the production stage. This resulted in declining gas production between 2011 and 2015; from 7,027 million standard cubic feet per day ("MMSCFD") ≈ 7,345 Billion Thermal Units per Day ("BBTUD") to 6,679 MMSCFD ≈ 6,900 BBTUD (a 5% decline). In contrast, overall domestic gas consumption in Indonesia increased by more than 13.3% over the same period. As a result, over the same period, Indonesia's gas export declined by 25.3% which resulted in Indonesia falling from being the world's largest LNG exporter in 2005 to the world's fifth-largest LNG exporter in 2014 behind Qatar, Malaysia, Australia and Nigeria.[32] The Government has a long-term plan to gradually decrease gas export volumes to zero in 2040.[33]

30 IEA (2015), *op.cit.*, p. 39.
31 SKK Migas (2015), *op.cit*. p. 32.
32 International Gas Union, World LNG Report – 2015 Edition, p. 9.
33 MoEMR. 2015. *Ekspor Migas Bakal Jadi Nol Persen, Penuhi Pasar Domestik. August 13th,2015.* (https://m.tempo.co/read/news/2015/08/13/090691560/ekspor-migas-bakal-jadi-nol-persen-penuhi-pasar-domestik)

Figure 4.2 Indonesian Natural Gas used for Production, Domestic Consumption, and Export (in MMSCFD) for 2011-2015



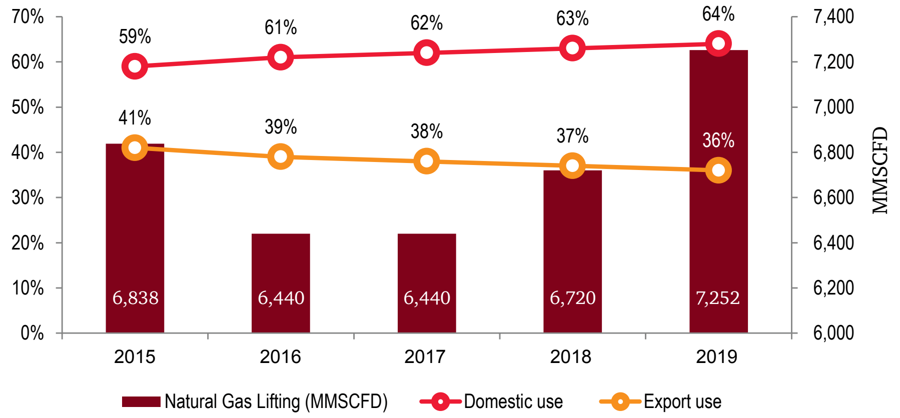
Source: LAKIP DJMGB 2015.

An increase in domestic gas demand, in particular for power generation, is projected over the period 2016 to 2025; this is consistent with both the 2016 RUPTL and the NEP. For power generation, the total gas required (including LNG) in 2019 is 761 bcf and in 2025 is 1,311bcf, as a result of the Government's plan to build 23 GW of new gas-fired power plant capacity by 2025. The expected increase in domestic use would also derive from the current committed and potential demand from industry, current committed demand by the power sector as well as the fertiliser industry. As a result, the Government plans to increase the allocation for domestic use from 59% in 2015 to 64% in 2019. The Government also expects an increase in gas production from 6,838 MMSCFD to 7,252 MMSCFD in 2019 (see Figure 4.3). Several projects that could support this increase in production include: Kepodang Field, Donggi Senoro, Indonesia Deep Water Development Bangka-Gendalo-Gehem, Jangkrik field and Tangguh Train-3.[34] Despite the fact that the production will increase, the Government forecasts that there will be a significant increase in domestic use, which may result in Indonesia starting to import gas significantly from 2019 (see Figure 4.4).[35]

34 LAKIP KESDM 2015, p. 19.

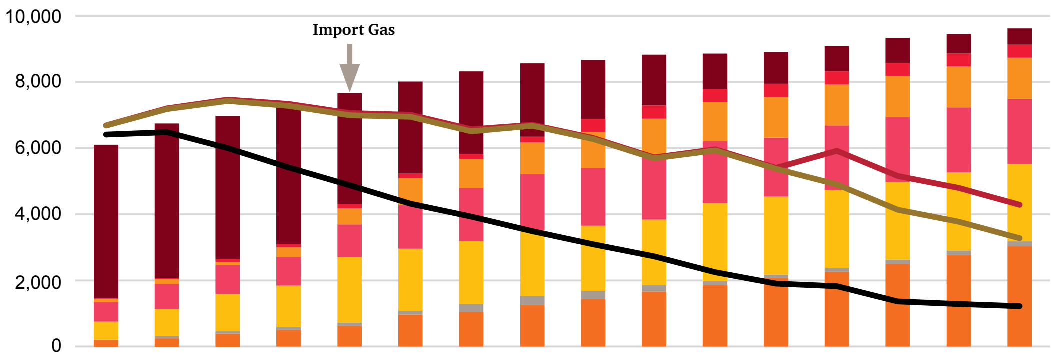
35 *IGN Wiratmaja (Direktur Jenderal Minyak dan Gas Bumi, "Dukungan Penyediaan Bahan Baku untuk Pembangunan Industri Berbasis Migas", 16 Februari 2016 (Presentasi)* [IGN Wiratmaja (Director General of Oil and Gas), "Supporting of Feedstock Supply for Developing Oil and Gas based Industry", 16 February 2016 (Presentation)], p. 13.

Figure 4.3 Indonesia Natural Gas Lifting (in MMSCFD) and Utilisation target for 2015 - 2019



Source: LAKIP DJMGB 2015

Figure 4.4. Natural Gas Balance for 2015 - 2030 (in MMSCFD)

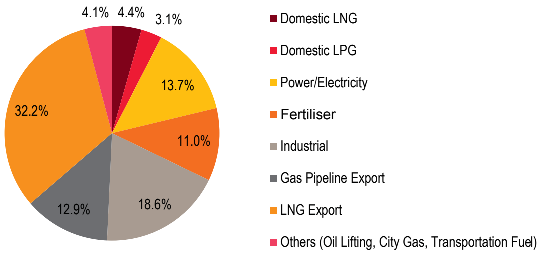


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
City Gas (Committed)	1	3	5	7	9	10	10	10	10	10	10	10	10	10	10	11
Potential Demand for Industry	198	258	396	504	622	966	1,049	1,260	1,443	1,661	1,855	2,064	2,260	2,496	2,762	3,022
Transportation (Committed)	20	63	75	79	104	116	231	260	243	196	118	111	120	130	142	154
Industry (Committed)	541	819	1,120	1,263	1,975	1,870	1,904	1,988	1,960	1,977	2,349	2,350	2,347	2,348	2,349	2,329
Electricity (Committed)	589	761	870	857	990	1,309	1,598	1,698	1,743	1,871	1,880	1,780	1,950	1,958	1,964	1,974
Fertiliser (Committed)	86	139	97	290	476	819	884	949	1,083	1,175	1,175	1,230	1,230	1,230	1,230	1,236
Lifting and Own Used (Committed)	27	27	90	98	128	139	150	176	396	396	396	396	396	396	396	397
Domestic (Contracted)	4,640	4,675	4,321	4,154	3,349	2,777	2,492	2,216	1,786	1,534	1,071	962	761	753	583	489
Potential Supply	2	17	42	61	61	61	61	25	22	22	22	22	1,022	1,022	1,017	1,014
Project Supply	265	694	1,429	1,866	2,127	2,636	2,587	3,207	3,200	2,975	3,700	3,482	3,082	2,777	2,488	2,047
Existing Supply	6,434	6,508	6,020	5,431	4,887	4,327	3,933	3,486	3,086	2,719	2,239	1,891	1,812	1,344	1,270	1,202

Source: IGN Wiratmaja (16 February 2016)

In 2015, natural gas in Indonesia amounting to 1,190 MBOE per day ≈ 6.7 MMSCFD was mainly utilised by five categories of users: LNG export, power sector, industrial sector, fertiliser sector and gas pipeline export. LNG exports account for more than a quarter of the total natural gas utilisation in Indonesia in 2015 (32.2%). Power, industrial, fertiliser and gas pipeline consumed approximately 13.7%, 18.6%, 11% and 12.9% of total Indonesian gas production (see Figure 4.5).

Figure 4.5 Indonesian Natural Gas Utilisation for 2015

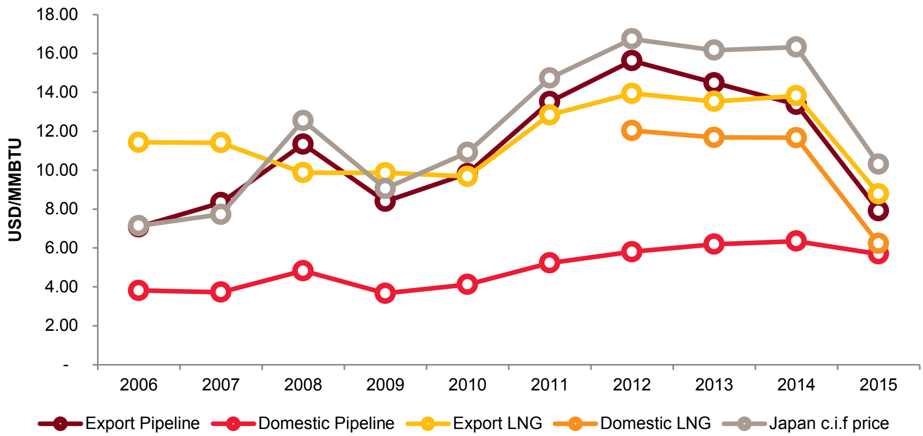


Source: IGN Wiratmaja (16 February 2016)

4.2.2 Price and regulation

Natural gas prices in Indonesia are low compared to international prices (both Indonesian export and Asian import prices) and government policy decisions are more dominant than market forces in determining the price and allocation. Based on MoEMR Regulation No. 6/2016, the Minister of Energy and Mineral Resources determines the allocation, utilisation and price for natural gas for domestic usage and/or export. At the end of 2015, Indonesian Domestic LNG was sold at USD 6.2 per Million British Thermal Unit ("MMBtu") to the domestic market compared with an Export LNG price of USD 8.8 per MMBtu in the same period (see Figure 4.6).

Figure 4.6 Indonesian Natural Gas Price and Japan c.i.f Price, 2006 – 2015



Source: IGN Wiratmaja (16 February 2016) and BP Statistical Review of World Energy June 2016

Reflecting falls in global LNG prices since mid-2014, the MoEMR has recently proposed to reduce the price of gas under ten Gas Sales and Purchase Agreements in Sumatera and Java from the current price levels above USD6 per MMBtu down to USD6 per MMBtu in order to help accelerate investment and economic growth.[36] This is supported by President Widodo, who already issued a presidential regulation on the gas price cut, PR No. 40/2016, in May 2016, and an implementing regulation based on MoEMR Regulation No. 16/2016.

The allocation and utilisation of natural gas in Indonesia is regulated by MoEMR Regulation No. 06/2016 (a revision of MoEMR Regulation No. 37/2015), which sets new priorities as follows:

1. To support the Government's programme of providing gas for transportation, households, and small users
2. To support national production of oil and gas
3. To provide raw materials for fertiliser
4. To support industries with natural gas as a raw material
5. To provide fuel to be used to produce electricity
6. To provide fuel to be used by other industries

Another key point in MoEMR Regulation No. 6/2016 is that the utilisation of natural gas for power generation can be allocated to: (a) a state-owned enterprise assigned to supply electricity i.e. PLN and its subsidiaries; (b) regional-owned enterprises located in the oil and gas producing areas which hold IUPTLs; (c) State-owned enterprises in oil and gas sector or regional-owned enterprises located in the oil and gas operating areas selling gas to IUPTL-holders; (d) business entities with an IUPTL that own gas-fired power plants; (e) business entities with a marketing permit to sell gas to IUPTL-holders.

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

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

Procedures and regulations for gas allocation and pricing are designed to ensure efficiency and effectiveness in the availability of natural gas as a fuel, raw materials or for other purposes in order to meet domestic demand optimally. The revision of the decree is due to the Government's initiatives in pushing the conversion of other power sources to gas, particularly for transportation and households use. Regulators have also sought to ensure that domestic demand becomes the first priority and the Minister of Energy and Mineral Resources has allowed imports of natural gas should domestic demand not be able to be fulfilled.

36 Petromindo Magazine, March – April 2016, p. 37.

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

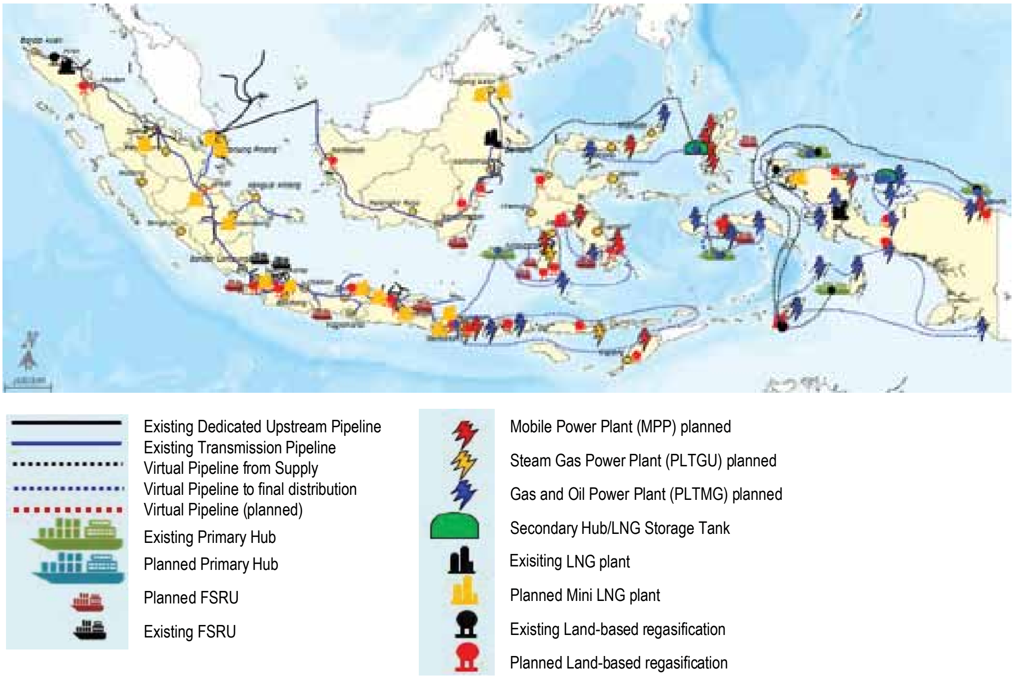
In 2015, power generation from gas-fired power plants accounted for 24.89% of total generation. To achieve the NEP target energy mix in 2025, it is expected that the share of gas-fired power generation in the power generation fuel mix will increase to 29.4% by 2025, supported by additional gas-fired power plant capacity of 23 GW. Gas consumption in Indonesia will likely be significantly increased if these additional gas-fired power plants come online. Most will be located in Java and Sumatera. In addition, an additional 5GW of gas-fired generation would be deployed as a contingency if the renewables target cannot be met by 2025.

To support domestic use, including for power generation, there are several gas infrastructure assets in operation; two Floating Storage and Regasification Units ("FSRUs") in West Java and Lampung, and one land-based gas receiving terminal unit (in Arun) are in operation. However, to accommodate the increase in domestic demand, there are at least 6 notable gas infrastructure asset development plans in Indonesia until 2019, such as LNG plant Donggi Senoro, LNG plant South Sulawesi, Receiving Terminal Banten, FSRU Central Java, LNG Tangguh Train-3 plant and LNG Masela. The Abadi gas-field (located in the Masela block in the Arafura Sea) was originally planned to be built as an offshore Floating LNG plant. However, in March 2016, President Widodo announced that the development should be based on an onshore platform, which is likely to delay the gas supply by several years as technical studies are completed and approvals granted again.

Furthermore, the Government has already developed a "Gas Infrastructure Concept" to support the development of the industry, which is estimated to require USD 24.3 billion of capital investment between 2015 and 2030 (see Figure 4.7 below) for pipeline construction, LPG plants and storage, gas fueling stations, regasification units, and liquefaction units[37] and to require some private sector participation. The development of gas infrastructure is planned to be conducted gradually. In the short term, the Government plans to build natural gas networks for households, gas fuel stations, and gas pipelines. Meanwhile, the private sector is expected to develop a gas receiving terminal to support the 35 GW programme. Figure 4.7 provides an overview of existing gas infrastructure, and the Gas Infrastructure Concept in Indonesia.

37 Director General of Oil and Gas Statements. 2016. "*Bangun Infrastruktur Gas, Pemerintah Libatkan Swasta*" (http://www.migas.esdm.go.id/post/read/bangun-infrastruktur-gas,-pemerintah-libatkan-swasta)

Figure 4.7 - Indonesia Gas Infrastructure – Current and Concept (2030)



Source: IGN Wiratmaja (16 February 2016)

4.2.4 Opportunities

Based on the 2016 RUPTL, the Government aims to increase the proportion of gas in the power generation mix to 29.4% in 2025, and initiate the conversion of PLN's existing diesel fuel-fired generation capacity to gas by constructing 23 GW of gas-fired power plants by 2025. Gas allocation is also prioritised for six groups (see page 74) in the domestic market including power generation, before being exported. Further, the Government has set a plan to reduce gas exports to only 40% of total production by 2019.

There are several IPPs and captive power plants located near supporting infrastructure (natural gas plants, ports, etc). Of the 23 GW of new gas-fired power capacity planned, 7 GW is planned to be developed by PLN, 7 GW by IPPs and 9 GW unallocated between IPPs and PLN.[38] These figures indicate that there are large opportunities in Indonesia for the private sector. Several notable gas-fired power projects to be tendered include Jawa 3 Combined Cycle (1 x 800 MW) – East Java, Jawa Bali 2 Combined Cycle (1 x 500 MW) - East Java, Jawa Bali 3 Combined Cycle (1 x 500 MW) – Banten. Further, several notable gas-fired power projects being tendered

38 2016 RUPTL, p.136.

include Jawa 1 Combined Cycle (2 x 800 MW) – West Java and Jambi Peaker gas/machine gas-fired (2 x 500 MW) – Jambi.

The Government also plans to increase the growth of FSRUs across Indonesia. This is possibly due to the fact that the typical costs of developing FSRUs are significantly lower than a land-based terminal of comparable size, and because generally FSRUs are faster to install than onshore regasification terminals.[39] Moreover, regarding the renewables target, there is also a possibility of an additional 5 GW of gas-fired generation capacity as a contingency in the event that the renewables target is not met. Receiving terminals like these present a potential private sector investment opportunity, especially for captive power generation for Industrial Estates in coastal areas.

To expedite the construction of gas-fired power plants, the Government has issued MoEMR No. 3/2015 regarding the FiT for gas-fired power plants which include gas turbines and gas machines as follows:

Capacity	40 - 60 MW	100 MW
Price (in cent USD/kWh)*	8.64	7.31
Assumptions:		
Availability Factor (AF)	85%	
Contract Period	20 years	
Heat Rate BTU/kWh**	9,083	8,000
Gas Price USD/MMBTU***	6.00	

*If the plant acts as a peaker, then the pricing takes into account availability.
**For machine gas, the heat rate is based on the heat rate determined by the manufacturer.
***Gas price is principally pass-through.

PLN may purchase power at a price above the benchmark price where it obtains approval from the MoEMR to do so.

4.2.5 Challenges

Lack of sufficient new infrastructure and aging existing infrastructure seems to be one of the bottlenecks in the power industry, and this is especially true for gas-fired power plants. Undeveloped infrastructure may lead to inefficient gas supply for power plants across Indonesia. As the current gas pipelines are not sufficient to distribute across Indonesia, especially in eastern Indonesia, the expansion of the pipeline network as well as the development of FSRUs and LNG facilities is required to support the distribution of gas.

39 Philip Weems, Nick Kouvaritakis and Richard Nelson, "FSRUs: Looking Back at the Evolution of the FSRU Market", December 2015. See http://www.energylawexchange.com/fsrus-looking-back-at-the-evolution-of-the-fsru-market/

PLN recently announced that it may supply the fuel for gas IPPs. The current process is that IPPs obtain fuel from their own suppliers and charge PLN through Component C of the power tariff, which is essentially a pass-through mechanism. PLN expects that with responsibility to secure gas in its hand, the financial close of IPP projects can be expedited. This is because the fuel risk should be reduced - the IPP will still get paid even if PLN fails to secure the gas. Furthermore, PLN intends to reduce its average gas purchase price by contracting large volumes for both IPPs and its own use. However, the impact of this potential new policy on the bankability of the project, fuel costs, and/or supply-chain complexity is uncertain and could go in either direction. In the absence of a detailed and confirmed mechanism it is not yet possible to comment. However, the uncertainty created is likely to have an adverse impact on ongoing tenders.

The implications of the power sector being only fifth on the list of priority sectors for gas supply (see page 74) are also yet to be fully understood.

4.3 Coal

4.3.1 Indonesian resources, consumption and production

Coal continues to play a vital role in global energy supply, with 68% of steam coal, coking coal, and lignite being used for the generation of electricity and commercial heat globally in 2013.[40] Currently, the coal industry is facing weak global demand, which, accompanied by an oversupply of coal, has led to steep declines in global coal prices. In the long term, world coal production is expected to continue to increase from 9 billion tonnes in 2012 to 10 billion tonnes in 2040.[41] World coal consumption also expected to increase, although China's consumption growth is expected to decline due to the implementation of policies addressing air pollution and climate change.

In Indonesia, coal has historically been, and remains, one of the most important sources of fuel for electricity. Moreover, coal mining has played a significant role in the Indonesian economy, contributing 2.1% to GDP in 2015.[42] According to the BP Statistical Review of World Energy 2016, Indonesia currently ranks as having the world's tenth-largest coal reserves, and the country contains roughly 3.1% of total global coal reserves. Around 92.4% of Indonesia's total coal reserves consist of cheaper, lower-quality coal (medium rank) with a calorific value of less than 5,700 kcal/kg. This type of coal is generally competitively priced on the international market.

40 IEA, Key Coal Trends Excerpt from: Coal Information, 2015, p. 18
41 US Energy Information Administration, International Energy Outlook 2016, p. 3.
42 Central Bureau of Statistics, GDP Based on Industrial Classification Data, 2015.

Table 4.1 – Indonesia's Coal Reserves and Resources for 2015

Quality	Resources (Million Tonnes)						Reserves (Million Tonnes)		
	Hypothetical	Infrerred	Indicated	Measured	Total	%	Probable	Proven	Total
Low Calorie (<5,100 kal/gr)	1,978.83	9,650.04	10,432.15	12,258.65	34,319.67	27.11	6,203.69	3,271.78	9,475.47
Medium Calorie (5,100 - 6,100 kal/gr)	16,882.21	22,413.42	17,441.12	24,286.35	81,023.10	63.99	16,485.65	3,858.21	20,343.86
High Calorie (>6,100 - 7,100 kal/gr)	889.19	2,804.47	2,186.22	3,243.11	9,122.99	7.21	545.20	974.33	1,519.53
Very High Calorie (>7,100 kal/gr)	13.61	1,276.46	394.02	459.49	2,143.58	1.69	761.51	163.31	924.82
Total	19,763.84	36,144.39	30,453.51	40,247.60	126,609.34	100.00	23,996.05	8,267.63	32,263.68

Source: LAKIP KESDM 2015

The three largest provinces with Indonesian coal resources are South Sumatra, South Kalimantan and East Kalimantan. There are also numerous smaller coal reserves across the rest of Sumatra and Kalimantan as well as on the islands of Sulawesi and Papua. The Indonesian coal industry is fragmented with only a few big producers and many small players that own coal mines and coal mine concessions (mainly in Sumatra and Kalimantan). In 2015, Indonesia has coal resources of 126.6 billion tonnes, mainly located in Kalimantan (68.2 billion tonnes), Sumatera (58 billion tonnes) and other regions (0.4 billion tonnes). In 2015, coal reserves amounted to 32.3 billion tonnes. Most of South Sumatera's coal reserves and resources are low rank coal, which will tend to be used for power generation. This is because it is generally not feasible to transport low rank coal to other regions, unless the coal price paid is significantly higher than average.

Table 4.2 – Reserves and Resources by Provinces for 2015

No	Island	Province	Resources (Million Tonnes)					Reserves (Million Tonnes)		
			Hypothetical	Inferred	Indicated	Measured	Total	Probable	Proven	Total
1	Java	Banten	5.47	5.75	4.86	2.72	18.80	0.00	0.00	0.00
2		Central Java	0.00	0.82	0.00	0.00	0.82	0.00	0.00	0.00
3		East Java	0.00	0.08	0.00	0.00	0.08	0.00	0.00	0.00
4	Sumatera	Aceh	0.00	346.35	13.89	90.40	450.64	0.00	0.00	0.00
5		North Sumatera	0.25	7.00	0.00	19.97	27.22	0.00	0.00	0.00
6		Riau	12.79	243.12	643.82	900.34	1,800.07	54.49	633.34	687.83
7		West Sumatera	20.41	294.50	231.16	249.45	795.52	0.00	158.43	158.43
8		Jambi	603.71	1,110.32	670.86	361.81	2,746.70	122.17	118.58	240.75
9		Bengkulu	0.00	2.12	118.81	71.14	192.07	0.00	18.95	18.95
10		South Sumatera	12,633.17	13,161.57	15,001.02	11,106.17	51,901.93	10,134.43	2,140.29	12,274.72
11		Lampung	0.00	106.95	0.00	0.94	107.89	0.00	0.00	0.00
12	Kalimantan	West Kalimantan	2.26	477.69	6.85	4.70	491.50	0.00	0.00	0.00
13		Central Kalimantan	222.24	1,952.18	883.86	1,047.20	4,105.48	284.53	486.73	771.26
14		South Kalimantan	0.00	6,050.60	3,461.10	4,945.92	14,457.62	1,300.59	2,354.54	3,655.13
15		East Kalimantan	6,088.84	11,623.63	8,807.33	20,543.66	47,063.46	11,793.92	1,968.40	13,762.32
16		North Kalimantan	65.62	660.81	480.27	850.09	2,056.79	305.86	388.31	694.17
17	Sulawesi	South Sulawesi	0.00	48.81	129.68	53.09	231.58	0.06	0.06	0.12
18		Central Sulawesi	0.00	17.11	0.00	0.00	17.11	0.00	0.00	0.00
19	Maluku	North Maluku	8.22	0.00	0.00	0.00	8.22	0.00	0.00	0.00
20	Papua	West Papua	93.66	32.82	0.00	0.00	126.48	0.00	0.00	0.00
21		Papua	7.20	2.16	0.00	0.00	9.36	0.00	0.00	0.00
Total Indonesia			19,763.84	36,144.39	30,453.51	40,247.60	126,609.34	23,996.05	8,267.63	32,263.68

Source: LAKIP KESDM 2015

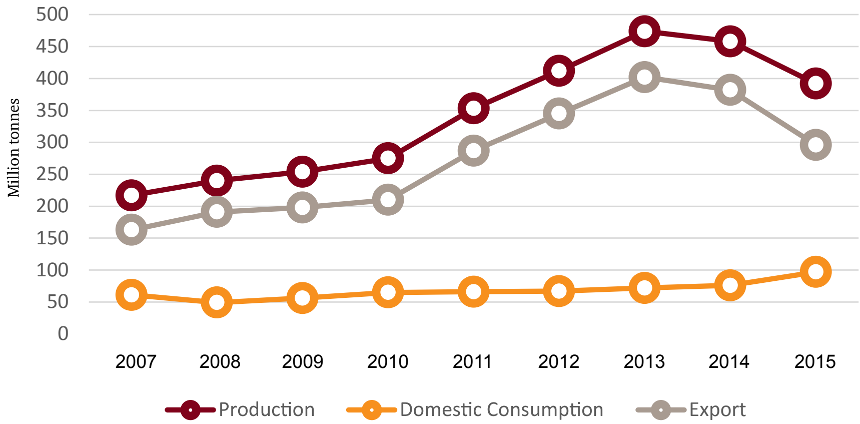
At current rates of consumption, proven coal reserves should last until 2036. This is consistent with our previous reports that the private sector is concerned about the availability of coal supply for power beyond 2036 if market prices do not recover sufficiently to incentivise capital expenditure (for further details, please see the recent PwC/ICMA publication “Supplying and Financing Coal-Fired Power Plants in the 35 GW Programme”).[43]

43 PwC and ICMA (March 2016), *op.cit*. p. 34.

As the world's fifth major coal producer, Indonesia has become the world's top exporter of thermal coal. Indonesia's coal production reached 474 million tonnes in 2013 and 458 million tonnes in 2014. However, in 2015, the production decreased to only 392 million tonnes despite the Government's plan to have a production of 425 million tonnes in 2015. Before the decline in coal demand worldwide, which has resulted in the declining coal price, the Government was planning to restrict coal production to only 400 million tonnes by 2019 – so 60% of production will be consumed domestically.[44]

In 2015, Indonesia exported 296 million tonnes out of a total coal production of 392 million tonnes, which generated USD15.9 billion in export earnings (see Figure 4.8).[45] The main export destinations for Indonesian coal have historically been China, India, Japan and Korea, although other countries such as the Phillipines are increasingly looking to import from Indonesia. In recent years, Indonesia's domestic coal consumption has increased by 22.8% from 65 million tonnes in 2010 to 79.8 million tonnes in 2015 mainly due to increased demand from coal-fired power plants (see Figure 4.9). This trend has continued in 2016, with an increase in domestic consumption of 2 million tonnes, while exports declined by 32 million tonnes in the first semester 2016.[46] Based on the 2016 RUPTL, coal-fired power plants are expected to consume 111 and 148 million tonnes of coal by 2019 and 2025, respectively.

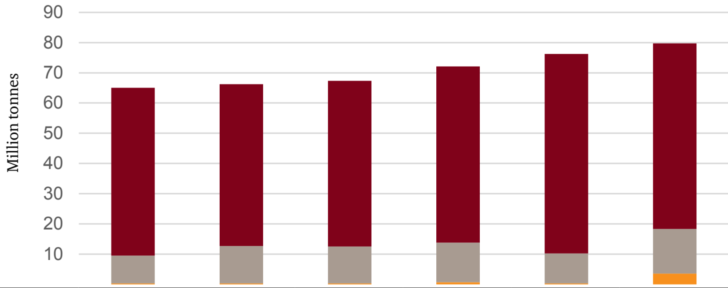
Figure 4.8 Indonesian Coal Production and Consumption for 2007-2015



Source: Ministry of Energy and Mineral Resources Data, 2015

44 RENSTRA KESDM 2015-2019, p. 85 and 87.
45 MoEMR data, 2015
46 *Bisnis Indonesia, "Permintaan Batu Bara: Produksi Anjlok, Konsumsi Lokal Jadi Andalan", 13 Juli 2016* [Bisnis Indonesia, "Coal Demand: Production Declined, Local Consumption becomes Important", 13 July 2016].

Figure 4.9 – Breakdown by type of consumers for domestic use for 2010- 2015



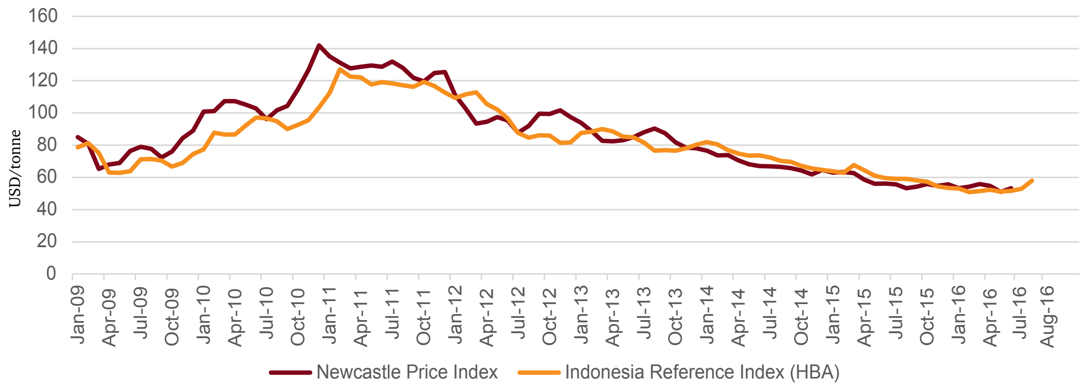
	2010	2011	2012	2013	2014	2015
Total	**65.0**	**66.2**	**67.3**	**72.1**	**76.2**	**79.8**
Metallurgy	0.3	0.3	0.3	0.7	0.3	3.6
Cement, Fertiliser, Pulp & Textiles	9.2	12.4	12.2	13.1	9.9	14.8
Power Plant	55.5	53.5	54.8	58.3	66.0	61.4

Source: Laporan Kinerja Tahun 2015 Direktorat Jenderal Mineral dan Batubara [2015 Performance Report of Directorate General of Mineral and Coal] and Renstra KESDM 2015-2019

4.3.2 Price and regulation

In recent years, the global coal price has plunged, followed by a sharply declining Indonesian coal reference price (*Harga Batubara Acuan* - "HBA") which has resulted in a decrease in coal production growth in Indonesia as small-scale miners suspended their operations and big players have taken steps to protect margins. The Indonesian coal reference price has declined by 58.3% from USD127.05/tonne in February 2011 to USD58/tonne in August 2016.

Figure 4.10 - Indonesian Coal Price for periods January 2009 – August 2016



Source: MoEMR, GEM Commodities, World Bank, 2015

The benchmark price for coal sales is regulated by MoEMR Regulation No. 17/2010 (as amended by MoEMR Regulation No. 66/2010), which states that the sale of coal should be aligned with the benchmark price issued by the Government. The HBA is calculated based on average coal prices in local and international market indexes, namely the Indonesia Coal Index, Newcastle Export Index and the Newcastle Global Coal Index for the previous month. The HBA is then used to determine a coal benchmark price (*Harga Patokan Batubara* - "HPB"), which is adjusted for individual coal quality characteristics.

The HPB is used as a basis for most IPP contracts. It is also applicable to spot sales and long-term sales. For long-term sales, there are several requirements for mining companies to determine the coal price. Every 12 months, mining companies need to adjust the sales price (as mentioned in Ministerial Regulation No. 17/2010), which is determined based on the weighted HPB for the preceding three months. Mining companies are also required to notify the Directorate General of Minerals and Coal ("DGoMC") of the proposed sales price before signing a long-term agreement.

On 4 April 2016, MoEMR Regulation No. 9/2016 on the Procedures for the Supply and Determination of Coal Price for Mine-Mouth Power Plants (which was later amended by MoEMR Regulation No. 24/2016) was issued replacing MoEMR Regulation No. 10/2014.

MoEMR Regulation No. 24/2016 provides that the coal price for mine-mouth power plants is to be based on the approved coal base price (allowed production cost plus a margin ranging from 15% to 25%) plus royalty or production fees. We note this differs from the previous MoEMR Regulation No. 9/2016, where the royalty was included in the production costs and thus subject to the 15-25% margin.

Based on MoEMR Regulation No. 24/2016, the coal base price should be negotiated between mining companies and mine-mouth power plant companies, and the results reported to MoEMR. The MoEMR will not get involved in cases where there is a deadlock in the negotiation. Under MoEMR Regulation No. 9/2016, in case of deadlock, MoEMR will make a decision on the margin. We note this differs from the previous system, which required approval from MoEMR first.

The approved coal base price can be escalated using a weighted average of the IDR exchange rate, fuel price, Consumer Price Index and regional minimum wage only after the COD of the power plant. The weights are determined on a case-by-case basis. As such, the inflationary risks from the approved coal base price and the COD of the power plant is borne by the coal supplier.[47]

MoEMR Regulation No. 9/2016 provides four criteria for a mine-mouth power coal supply arrangement: (1) the coal to be used is more economically feasible for utilisation in a mine-mouth power project; (2) the availability of coal supply is guaranteed by the coal mining company throughout the operation of a plant; (3) the power plant is at most 20 km away from the location of the coal mine; and (4) the coal does not include transportation costs except for transportation costs from the mine location to the power plant's stockpile.

47 Coal Asia, 25 June – 25 July 2016, p. 54.

However, it is not clear under this regulation whether the DGoMC has the authority to determine whether or not a project meets the criteria for a mine-mouth power plant project.

In addition, a mine-mouth coal supplier or its affiliate must have a minimum equity interest of 10% in the IPP and must be the holder of a production mining business licence ("IUP Operasi Produksi"), a special operation mining business licence ("IUPK Operasi Produksi"), or a Coal Cooperation Agreement (Perjanjian Karya Pengusahaan Pertambangan Batubara - "PKP2B").

All PPAs signed prior to the issuance of MoEMR Regulation No. 24/2016 should be revised to reflect this regulation.

4.3.3 Current installed coal-fired power plant capacity and the Government plans

In 2015, power generation from coal-fired power plants accounted for 56% of total generation. In order to achieve the target NEP energy mix in 2025, it is expected that power generation from coal will reduce to 50% by 2025, despite additional coal-fired power plants of 34.8 GW. Coal consumption in Indonesia will likely be significantly increased due to these additional power plants.

As discussed in section 3.7.1, coal will likely continue to play a vital role in development of power generation in Indonesia for the next ten years. Coal mine-mouth power plants remain integral to the Government's plans given that Indonesia's low-rank coal deposits are often located in remote areas with minimal infrastructure making transportation of the coal uneconomical.

4.3.4 Opportunities

The Government plans to build 34.8 GW of coal-fired power plant capacity. Of the 34.8 GW of new coal-fired power capacity planned, 8 GW is planned to be developed by PLN, 25.1 GW by IPPs and 1.7 GW is unallocated between IPPs and PLN.[48] These figures indicate that there are significant opportunities in Indonesia for the private sector. Several notable coal-fired power projects to be tendered include the Jambi Coal-fired Power Plant (2 x 600 MW) – Jambi, Jawa 10 Coal-fired Power Plant (1 x 660 MW) – Central Java and Riau Kemitraan Coal-fired Power Plant (2 x 600 MW) – Riau. Further, several notable coal-fired power projects currently being tendered include Sumsel 9 and 10 and Jawa 5 Coal-fired Power Plants (2 x 1,000 MW).[49]

48 2016 RUPTL, p. 136.
49 Bisnis Indonesia, "*Berebut Bisnis Setrum*", 9 Juni 2016.

To expedite the construction of coal-fired power plants, the Government has issued MoEMR No. 3/2015 on FiT for coal-fired power, which regulates the ceiling levelised price for non-mine-mouth coal power as follows:

Capacity (in MW)	≤10	15	25	50	100	150	300	600	1,000
Price (in cent USD/kWh)	11.82	10.61	10.60	9.11	8.43	7.84	7.25	6.96	6.31
Assumptions:									
Availability Factor (AF)	80%								
Contract Period	25 years								
Heat Rate Kcal/kWh	4,160	3,500	3,450	3,200	3,000	2,800	2,600	2,450	2,290
Caloric Value (gar) Kcal/kg	5,000								
Price USD/tonne (CIF)*	60								

*Coal price is principally pass-through.

PLN may purchase power at a price above the benchmark price where it obtains approval from the MoEMR to do so.

Another opportunity for IPPs and miners is to develop coal mine-mouth (“CMM”) power plants. These coal mine-mouth power plants represent an opportunity for private sector investors, especially those looking to avoid a public tender process. A list of proposed CMM projects is included in Figure 4.11 below (note that not all of these are included in the 2016 RUPTL).

MoEMR Regulation No. 3/2015 also regulates the ceiling levelised base price for CMM power plants. The ceiling price varies according to the unit capacity and heat rate as described in the following tables:

Capacity	100 MW	150 MW	300 MW	600 MW
Price (in cent USD/kWh)	8.2089	7.6520	7.1862	6.9012
Assumptions:				
Availability Factor (AF)	80%			
Contract Period	30 years			
Heat Rate Kcal/kWh	3,200	3,000	2,900	2,700
Caloric Value (gar) Kcal/kg	3,000			
Price USD/tonne (CIF)*	30			

*Coal price is principally pass-through.

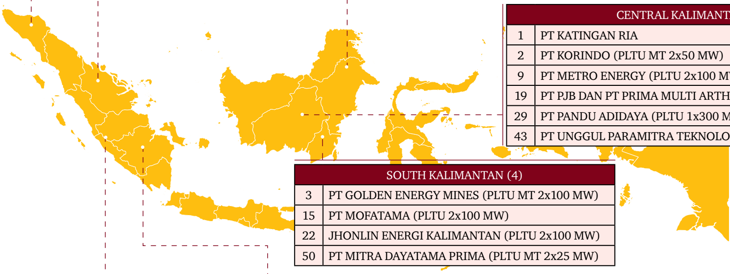
Figure 4.11. List of Mine-Mouth Power Plant Proposals as of June 2016

ACEH (2)	
23	PT ABM INVESTAMA TBK
34	AGRABUDI JASA BERSAMA-SATRIA MANGGALA-SHANGHAI PPE-SKODA ENERGO-VITKOVICE (PLTU MT 2x100 MW)

RIAU (4)	
4	PT PERMATA ARUN ENERGI
13	PT SAMANTAKA BATUBARA (PLTU MT 2x300 MW)
24	PT BUKIT ASAM (TBK)
27	PT TRIKA HUADIAN (PLTU MT 2x500 MW)

EAST KALIMANTAN (13)	
6	PT RESOURCE ALAM INDONESIA (PLTU 2x100 MW)
10	ESSAR GROUP (PLTU MT 2x50 MW)
16	PT KIDECO JAYA AGUNG
17	PT ADIMITRA BARATAMA NUSANTARA (PLTU MT 2x100 MW)
18	PT MUARA WAHAU ENERGY (PLTU MT 100 MW, 200 MW, 300 MW)
20	PT POWER ALAM LESTARI (PLTU 2x100 MW)
25	PT MEO (PLTU 300 MW)
26	PT NATRUSTPARADIGMA LISTRIK MANDIRI (PLTU MT 2x100 MW)
40	PT ADARO (PLTU MT 2x100 MW)
41	PT BUMI RESOURCES TBK (PLTU MT 2x200 MW)
44	PT TEKNOLOGI PERMATA INDONESIA (PLTU MT 2x150 MW)
45	KUTAI BARAT ENERGI (PLTU MT 2x100 MW)
52	PT KALTIM PRIMA COAL (PLTU MT 2x200 MW)

CENTRAL KALIMANTAN (6)	
1	PT KATINGAN RIA
2	PT KORINDO (PLTU MT 2x50 MW)
9	PT METRO ENERGY (PLTU 2x100 MW)
19	PT PJB DAN PT PRIMA MULTI ARTHA (PLTU MT 2x100 MW)
29	PT PANDU ADIDAYA (PLTU 1x300 MW)
43	PT UNGGUL PARAMITRA TEKNOLOGI (PLTU MT 2x135 MW)



SOUTH KALIMANTAN (4)	
3	PT GOLDEN ENERGY MINES (PLTU MT 2x100 MW)
15	PT MOFATAMA (PLTU 2x100 MW)
22	JHONLIN ENERGI KALIMANTAN (PLTU 2x100 MW)
50	PT MITRA DAYATAMA PRIMA (PLTU MT 2x25 MW)

JAMBI (10)	
3	PT GOLDEN ENERGY MINES (PLTU MT 2x600 MW, 2x100 MW)
7	MNC ENERGY AND NATURAL RESOURCES
31	PT BBM MEGA ENERGI (PLTU MT 2x600 MW)
32	PT JAMBI LESTARI POWER (PLTU MT 2x500 MW)
33	PT PEMBANGKITAN PETRA DAYA (PLTU MT 2x600 MW)
36	PT TITAN MULTI POWER (PLTU MT 2x150 MW)
37	PT ENERGI INDONESIA BERSAMA (PLTU MT 2x600 MW)
42	PT INTITIRTA PRIMA SAKTI (PLTU MT 2x600 MW)
54	PT TRIARYANI (PLTU MT 2x600 MW)
55	PT GLOBALINDO ALAM LESTARI (PLTU MT 2x150 MW)

SOUTH SUMATERA (18)	
5	PT BARA MITRA PERKASA (PLTU MT 4x150 MW/ 2x300 MW)
6	PT BHINAMITRA USAHAPERSADA (PLTU MT 2x300 MW)
11	PT ADHI KARYA (PERSERO) TBK (PLTU 2x150 MW)
12	KONSORSIUM UCOAL-CHEC (PLTU 3500 MW)
14	PT GUMAY NIAGA ENERGI (PLTU MT 25 MW)
21	PT TEMPIRAI INTI ENERGI (PLTU 2x200 MW)
24	PT BUKIT ASAM (TBK)
25	PT DSSP (PLTU MT 1x300 MW)
30	PT ENERGI MUSI MAKMUR (PLTU MT 2x300 MW)
35	PD PERTAMBANGAN DAN ENERGI SUMSEL (PLTU MT 2x115 MW)
38	SHENHUA PT GH EMM INDONESIA (PLTU MT 2x350 MW)
39	BARAMULTI SUGIH & TUAS ENGINERING (PLTU MT 2x300 MW)
46	ENERGI ALAM RAYA, POWER CHINA SHANGHAI ELECTRIC POWER (PLTU MT 2x300 MW)
47	MNC DAYA (PLTU MT 2x300 MW)
48	PT INTIPUTERA KANAAN (PLTU MT 1x150 MW)
49	PT GUMAY PRIMA ENERGI (PLTU MT 2x200 MW)
51	PT BARA SUMATERA ENERGI (PLTU MT 2x300 MW)
53	PT SUMBER ALAM MAKMUR UTAMA (PLTU MT 2x300 MW)

Source: PLN, Daftar Peminat IPP PLTU Mulut Tambang, Juni 2016 [PLN, List of Coal Mine-mouth IPPs' Power Plants, June 2016]

Despite declines in the Indonesian coal reference price, there is more positive sentiment in the coal mining industry from the Government's coal power plant expansion plan. PLN has projected that there will be an additional 87 million tonnes of coal required for power plants by 2025 compared to 61 million tonnes used by power plants in 2015.

4.3.5 Challenges

Indonesia's coal reserves may not be sufficient to supply all of the new coal-fired power plant capacity added by the 35 GW programme beyond 2036 due to downward pressure on the price of coal, and undermining by the incentives to invest.[50] In addition, although mature in some areas, coal transport infrastructure still contributes significantly to f.o.b. coal prices in many areas. Efficient solutions such as railways (with high capital requirements but generally lower lifetime costs) will need to be accelerated if inland coal is to be accessed cost-effectively.

Licensing requirements could also hinder the progress of the coal development programme since many concessions for coal mining are expected to expire before the corresponding Coal Supply Agreements (in the early 2020s). The Government may need to signal to reputable miners that it will commit to renewing Mining Business Licences (*Izin Usaha Pertambangan* – "IUP") or PKP2B.

It was reported earlier in 2016 that PLN disagreed with the margin of 15 – 25% for coal mine-mouth power plants as discussed above.[51] This may potentially disrupt the development of planned coal mine-mouth power plants. MoEMR Regulation No. 24/2016 reduces this cost to PLN to some extent by applying the 15-25% margin to pre-royalty production costs (rather than production costs including royalty as per MoEMR Regulation No. 9/2016). However, it remains to be seen whether this relatively small change in cost will change the affordability of the mine mouth coal payments for PLN.

4.4. Oil

Indonesia is now a net oil importer. In 2015, Indonesia's total crude oil production amounted to 0.78 million barrels per day, which was around 71% of its 2005 daily production.[52] Meanwhile, in 2015, Indonesia's total oil consumption has decreased by 3.2% to 1.63 million barrels per day.[53] A dependency on imports of oil and refined oil products has induced the Government to subsidize some refined oil products.[54] However, in 2015, the Government took the opportunity of declining global oil prices to begin to reduce the subsidy allocation in the state budget. In the long term, the Government plans to continue to reduce subsidy allocation despite a recovery of the oil price in 2016, and intends to allocate the budget to infrastructure development.

50 PwC and ICMA (2016), *op.cit.,*p. 9.
51 Bisnis Indonesia, *"KISRUH MARGIN BATU BARA: Babak Baru Seteru PLTU Mulut Tambang"*, 21 July 2016.
52 LAKIP DJMGB 2015, p. 26.
53 BP Statistical Review of World Energy 30 June 2016, p. 9.
54 PwC, Oil and Gas in Indonesia, May 2016, p. 6.

In 2035, oil demand is projected to grow at an average annual rate of 1.1%, reaching 2.1 million barrels per day.[55] Currently, around 40% of Indonesia's energy consumption is derived from oil.[56] Thus, in order to decrease the use of oil, the Government, through DEN, has issued Government Regulation 79/2014 regarding National Energy Policy, which aims to decrease the use of oil to a maximum of 25% of the total energy used in 2025 and a maximum of 20% in 2050, by placing more emphasis on renewable sources and coal.[57]

Meanwhile, despite the increase in oil consumption, the use of oil for power generation is expected to decrease in the long term as the Government plans to phase out the use of oil-based fuels such as Marine Fuel Oil and High Speed Diesel for new power plants and actively encourage private-sector investment in alternative energy. With the effective phasing out of oil from the power generation mix over the next 10-15 years (its contribution is expected to be only 0.6% by 2025), IPP investment opportunities in this space are less obvious than in other sectors.[58]

55 Dewan Energi Nasional, Outlook Energi Indonesia 2015, November 2015, p. 42.
56 2015 Handbook of Energy and Economic Statistics of Indonesia, p. 27.
57 GR No. 79/2014 Article 9.
58 2016 RUPTL, p. 161.

Photo source: PwC

5. Renewable Energy

Photo source: PwC

5.1 Overview of renewable energy

Despite an abundance of renewable energy resources (see Table 1.1), Indonesia has been relatively slow in developing renewable energy. In the past, fuel subsidies, low electricity tariffs, complex regulations, legal uncertainties, logistical challenges and extensive cheap coal resources have deterred potential renewables investors. Following years of under-investment, Indonesia's production of renewable energy remains modest.

Indonesia's primary intent in expanding its use of renewable energy appears to be threefold:
a) To improve domestic energy security by diversifying the feedstocks used by PLN and private sector IPPs to generate utility-scale power;
b) To accelerate improvements in the electrification ratio and access to energy infrastructure, particularly for that part of the population without grid access in rural, remote and border areas and on islands; and
c) To encourage the use of renewable energy as an ancillary source of energy where it is readily available and untapped (for example waste to energy plants or rooftop photovoltaic solar in urban areas).

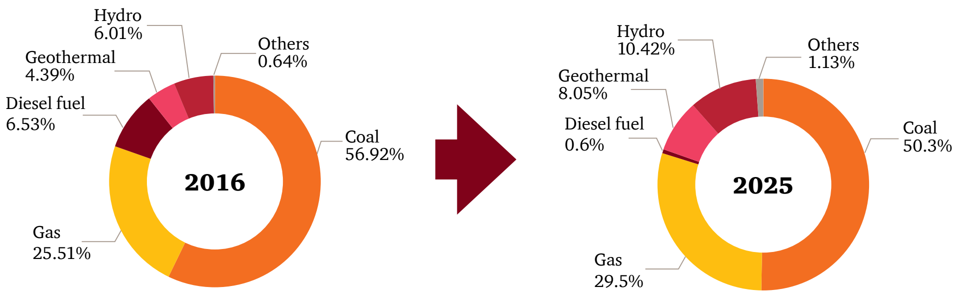
Similarly, the present utilisation of renewable energy sources for power generation in Indonesia can be broken down into three classes:
a) Those energy sources already being used in commercial operations (e.g. geothermal, hydro energy and biomass);
b) Those energy sources being developed commercially but on a limited basis and with some concerns over regulatory and commercial issues (e.g. solar and wind); and
c) Those energy sources at a research stage only (e.g. ocean energy).

The most recent 2014 NEP sets the goal for the percentage of primary energy from new and renewable energy sources to be 23% by 2025 and 31% by 2050 (up from 6.8% in 2016).[59] Under Law No. 30/2007 on Energy, new energy sources are defined to include liquefied coal, coal bed methane, gasified coal, nuclear energy and hydrogen. Renewable energy sources are defined to include geothermal resources, hydropower, bioenergy, solar, wind and ocean energy. The composition of the 23% target has been reported by the MoEMR as comprising: bioenergy 10%, geothermal 7%, hydropower 3% and other new and renewable energy 3%. Note that not all of this energy output would be used in the context of power production, for example, biofuels represent a significant proportion of the bioenergy target. The focus of this chapter is the utilisation of renewable energy, rather than new energy for power generation.

As discussed in Section 3.7.1 - The 2016 RUPTL – the greater role of the private sectors, the 2016 RUPTL focuses on renewables as dictated by the 2014 NEP. The fuel mix projection in the electricity sector is depicted in Figure 5.1 below. Based on the 2016 RUPTL, the fuel mix projection for renewables will not be 25% (only 19%) and it will be replaced by gas if the renewable target is not met.

59 MoEMR presentation on Action for Achieving the 2025 Renewable Energy Target p. 6 on 12 February 2016 at the Bali Clean Energy Forum. (http://bceforum.org/?page_id=2625)

Figure 5.1 – Fuel Mix Projection in the Electricity Sector for 2016-2025



5.2 Geothermal Energy

Geothermal power generation relies on the thermal energy of the Earth's core to heat water or another fluid. The heated fluid is used to turn a turbine and generate electricity. After cooling, the fluid is directed back down toward the geothermal resource to repeat the process.

Geothermal is regarded as a "clean" energy, emitting up to 1,800 times less carbon dioxide than coal-fired burning plants and 1,600 times less than oil-fired burning 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 close to 100%.

Indonesia's geothermal potential reaches 29,543 MWe (See Table 5.1) across 329 locations, and represents the second largest geothermal resource in the world, at 28% of total global resources.[60]

Table 5.1 - Resources and Installed Capacity of Indonesian Geothermal for 2015

No	Island	No. of Locations	Potential Energy (MWe)					Total Potential	Installed Capacity
			Resources		Reserves				
			Speculative	Hypothetical	Possible	Probable	Proven		
1	Sumatera	97	3,091	2,408	6,992	15	380	12,886	122
2	Java	73	1,560	1,739	4,023	658	1,815	9,795	1,224
3	Bali-Nusa Tenggara	33	301	535	1,052	-	15	1,903	12
4	Kalimantan	14	153	-	90	-	-	243	-
5	Sulawesi	76	1,239	302	1,451	150	78	3,220	80
6	Maluku	33	532	89	800	-	-	1,421	-
7	Papua	3	75	-	-	-	-	75	-
	Total	**329**	**6,951**	**5,073**	**14,408**	**823**	**2,288**	**29,543**	**1,438**
			12,024		**17,519**				

Source: LAKIP KESDM 2015 and PwC Analysis

60 RENSTRA KESDM 2015 – 2019, p. 70.

The physical location of geothermal resources across Indonesia and their lack of "tradability" means that this power source is well-placed to assist in improving domestic energy security. The development of Indonesia's geothermal sector has been slow because only nine working (or concession) areas are producing despite the fact that the Government has identified 67 potential working areas. With only 1,438 MW of capacity currently installed (see Table 5.2 for the operating working areas), the Government plans to achieve around 3,200MW of installed geothermal power capacity by 2019, a more-than-twofold increase since the end of 2015 (see the statistical analysis below for proposed on-stream development). Further, of the 25% target for the new and renewable energy share of the power generation fuel mix, it is anticipated that geothermal will account for about 7,500 MW in installed capacity, requiring an investment of funds in excess of USD25 billion. Recent progress in developing geothermal resources suggests that this may be an ambitious target.

Table 5.2 - Installed Geothermal Capacity as at 2015 by Licence Holder and Developer

No	Geothermal Working Area Location	License Holder	Developer	Power Plant	Installed Capacity (MW)	Turbine Capacity (MW)
1	Sibayak – Sinabung, North Sumatera	PT Pertamina Geothermal Energy ("PGE")	PGE	Sibayak	12	1 x 10 2MW
2	Cibeureum – Parabakti, West Java	PGE	JOB – Chevron Geothermal Salak, Ltd	Salak	376.8	3 x 60 3 x 65.6
3	Pangalengan, West Java	PGE	JOB – Star Energy Geothermal Wayang Windu, Ltd	Wayang Windu	227	1 x 110 1 x 117
	Pangalengan, West Java	PT Geo Dipa Energi ("GDE")	GDE	Patuha	55	1 x 55
4	Kamojang – Darajat, West Java	PGE	PGE	Kamojang	235	1 x 30 2 x 55 1 x 60 1 x 35
	Kamojang – Darajat, West Java	PGE	JOB – Chevron Geothermal Indonesia, LTD	Darajat	270	1 x 55 1 x 94 1 x 121
5	Dataran Tinggi Dieng, Central Java	GDE	GDE	Dieng	60	1 x 60
6	Lahendong – Tompaso, North Sulawesi	PGE	PGE	Lahendong	80	4 x 20
7	Ulubelu, Lampung	PGE	PGE	Ulubelu	110	2 x 55
8	Ulumbu, NTT	PT PLN Geothermal ("PLN G")	PLN G	Ulumbu	10	4 x 2.5
9	Mataloko, NTT	PLN G	PLN G	Mataloko	2.5	1 x 2.5

Source: Rozaq, Rahayu, and Bramantio PT Pertamina Geothermal Energy ("Development of Geothermal in Indonesia, World Geothermal Congress 2015" https://pangea.stanford.edu/ERE/db/WGC/papers/WGC/2015/08006.pdf p.3 edited to show turbine capacity). Information added based on Statistik EBTKE 2015 [2015 New and Renewable Energy and Energy Conservation Statistics] and LAKIP KESDM 2015

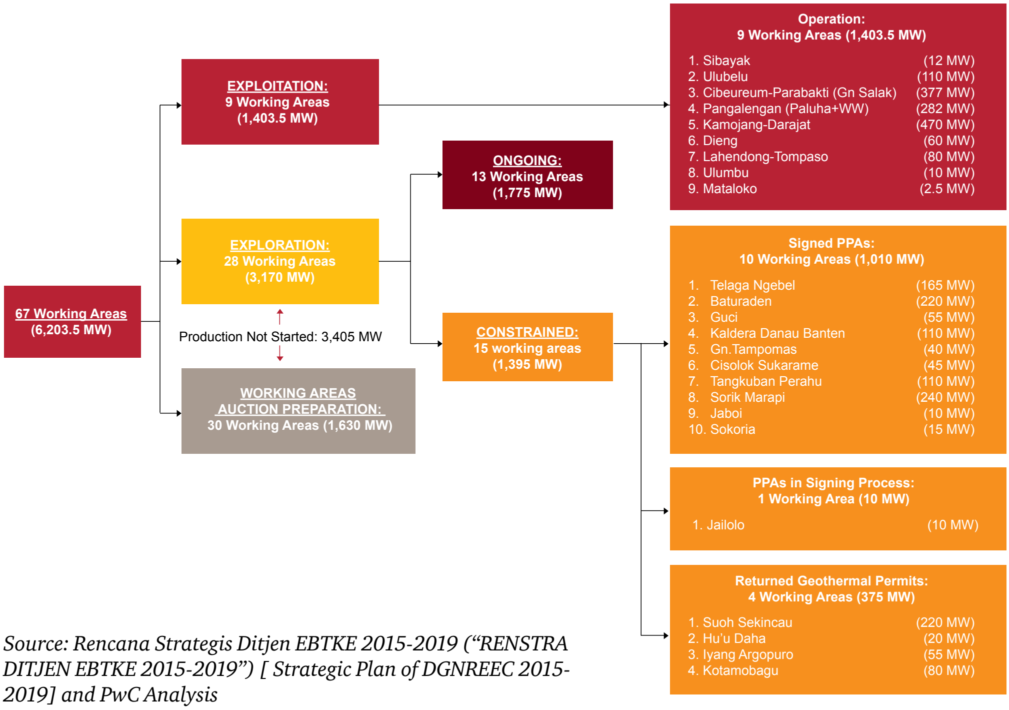
In 2015, there were 67 geothermal working areas stipulated by the Government, which comprise 19 existing working areas identified prior to the issuance of Law No. 27/2003 on Geothermal, 46 working areas stipulated after the issuance of Law No. 27/2003 and 2 working areas identified after the issuance of Law No. 21/2014 (see Figure 5.2).

To expedite the development of geothermal in open areas that have not yet been stipulated as working areas, the Government can give a Preliminary Geothermal Survey Assignment to Business Entities on Working Areas with the following criteria:

1. The open areas have huge geothermal potential and/or demand for electricity in that area is significant.
2. Those areas have sufficient infrastructure and national transmission network capacity.
3. The location is in a frontier/remote area with geothermal potential that if developed would provide a significant multiplier effect.

It is expected that the preliminary survey will be able to convert open areas into working areas that can be developed. The Assigned Business Entity will have the “right to match” when the working areas are tendered later.

Figure 5.2 - The status of the 67 working areas



Source: Rencana Strategis Ditjen EBTKE 2015-2019 (“RENSTRA DITJEN EBTKE 2015-2019”) [Strategic Plan of DGNREEC 2015-2019] and PwC Analysis

The Government has ambitious goals for additions to geothermal capacity from 2015 – 2019 as follows:

	2015	2016	2017	2018	2019
Installed capacity – beginning of year	**1,404**	**1,439**	**1,713**	**1,977**	**2,611**
Planned Additions:					
Kamojang Unit 5	35				
Ulubelu Units 3 and 4		55	55		
Lahendong Units 5 and 6		20	20		
Sarulla Units 1, 2 and 3		114	119	119	
Karaha Bodas Units 1 and 2		30			60
Lumut Balai Units 1, 2 and 3		55		55	55
Muaralaboh			70		
Tulehu				20	
Rantau Dedap				220	
Rajabasa Units 1 and 2				110	110
Hululais Units 1 and 2				55	55
Dieng Units 2 and 3				55	55
Patuha					110
Sungai Penuh					55
Cisolok Cisukarame					45
Kotamobagu					40
Construction of geothermal plants	**35**	**274**	**264**	**634**	**585**
Installed capacity – end of year	**1,439**	**1,713**	**1,977**	**2,611**	**3,196**

Source: RENSTRA KESDM 2015 – 2019

From 2010–2014, just 214.5 MW was added and no PPAs were signed under the 2012 feed-in tariffs. A significant change in the pace of development and coordination of efforts by all stakeholders is likely to be needed for 3,200 MW of installed capacity to be reached by 2019.

After being initiated in 1990, the 330 MW Sarulla geothermal project in North Sumatra is being developed by a consortium of investors from Japan, the US and Indonesia. It achieved financial close in 2014 and is the first greenfield Indonesian geothermal project financed on a limited recourse basis since the Wayang Windu project in 1997. It is anticipated to commence its first phase of operations in 2016 and be completed by 2018/2019.

Kamojang 5 – 35 MW went on-stream in 2015. The Government has confirmed that four geothermal power plants will come on-stream in 2016, namely Ulubelu (55 MW), Lahendong (20 MW), Karaha Bodas (30 MW) and Sarulla (110 MW). As such, in 2016 there will be an increase in geothermal power plant capacity of 215 MW. Despite the encouraging results of several of these projects, several projects that had been planned to come on-stream by 2017 – 2019 have not yet even started construction. This may delay the Government's target of achieving 3,200 MW of installed capacity of geothermal power plants by 2019.

In order to achieve the target of 7,500 MW by 2025, the MoEMR planned to auction 30 geothermal work areas in the period of 2016 - 2017 or at a later date through open tender or the direct appointment of SOEs (PGE, PLN G and GDE) as follows:

Block	Capacity (MW)	Estimated Investment	Status
Bonjol	60	USD 240 million	Open
Gunung Talang Bukit Kili	20	USD 80 million	Re-tender in 2016
Gunung Endut	40	USD 160 million	Open
Candi Umbul Telomoyo	55	USD 220 million	Assigned to GDE
Gunung Wilis	20	USD 80 million	Tender in 2016
Gunung Arjuno Welirang	110	USD 440 million	Assigned to GDE
Gunung Pandan	10	USD 40 million	Open
Gunung Gede Pangrango	55	USD 220 million	Assigned to PGE
Songgoriti	20	USD 80 million	Open
Sipoholon Ria-Ria	20	USD 80 million	Open
Simbolon Samosir	110	USD 440 million	Tender in 2016
Graho Nyabu	110	USD 440 million	Tender in 2016
Suwawa	20	USD 80 million	Open
Sembalun	20	USD 80 million	Assigned to PLN G
Oka-lle Ange	10	USD 40 million	Open
Bora Pulu	40	USD 160 million	Open
Gunung Hamiding	10	USD 40 million	Tender in 2016*
Songa Wayaua	5	USD 20 million	Open
Gunung Geureudong	110	USD 440 million	Open*
Gunung Galunggung	110	USD 440 million	Tender in 2016*
Gunung Ciremai	110	USD 440 million	Open
Way Ratai	55	USD 220 million	Optima Nusantara Energy & Enel Green Power SPA won the tender
Gunung Lawu	165	USD 660 million	PGE won the tender
Kepahiang	110	USD 440 million	Tender in 2016
Danau Ranau	110	USD 440 million	Tender completed - no winner
Marana	20	USD 80 million	Re-tender in 2016
Seulawah Agam	55	USD 220 million	Tender in 2016
Telaga Ranau	10	USD 40 million	Tender in 2016
Ciater	30	USD 120 million	Re-tender
Atedai	10	USD 40 million	Re-tender

Source : Statistik EBTKE 2015; Bisnis Indonesia 19 March 2016; Bisnis Indonesia 30 December 2015; Investor Daily 30 March 2016; Investor Daily 18 January 2016; Bisnis Indonesia 29 March 2016; Jakarta Post 3 March 2016; Jakarta Post 20 April 2016; Bisnis Indonesia 10 May 2016; Investor Daily 4 July 2016; Detik Finance 13 November 2015; PwC Analysis.

* When they are tendered, the private investors who performed the preliminary survey have the "right to match".

Based on the preliminary survey performed, there are at least two areas which will be stipulated as working areas, i.e. Tanjung Sakti and Empat Lawang Areas – South Sumatera.[61] These working areas may be tendered in the near future in addition to the 30 working areas.

5.2.1 The 2014 Geothermal Law

Law No. 27/2003 (the "2003 Geothermal Law") allowed private sector control over geothermal resources and the sale of base load electricity to PLN. GR No. 59/2007, as amended by GR No. 70/2010 on Geothermal Business Activities are the enacting regulations for geothermal development in Indonesia and those GRs are yet to be replaced under Law No. 21/2014 on Geothermal (the "2014 Geothermal Law").

The 2003 Geothermal Law took over from the integrated geothermal and power arrangements covered under the former Joint Operation Contract 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 arguably inconsistencies between the tendering process at the local level and the subsequent price negotiations in the PPAs with PLN. This may be because PLN is centrally controlled while the IUP - Geothermal may be granted by the Central, Provincial or Local Government depending upon the location of the work area and whether it crosses provincial or local boundaries. This means that investors were effectively negotiating with two parties.

To expedite the utilisation of geothermal, on 17 September 2014, the Government issued the 2014 Geothermal Law. Under the 2014 Geothermal Law, geothermal operations are classified being either for direct use, for example hot springs, or indirect use, that is electricity generation. Only the Central Government can issue an IPB and conduct a tender for 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 is that geothermal activities are no longer considered to be mining activities. As a corollary of this, the law specifically allows geothermal activities to be conducted in production, protected and conservation forest areas, where much of Indonesia's geothermal resources are found (an estimated 42%). Previously, as geothermal activities were considered mining, working areas were restricted under the Forestry Law.

The 2014 Geothermal Law requires geothermal permit holders to provide a "production bonus" to the Local Government covering the permit holder's working area, which will be a specified percentage of the gross revenue from the date of commercial operations of the first unit. The amount and procedure for the bonus payment is regulated under GR No. 28/2016.

61 http://www.cnnindonesia.com/ekonomi/20151022164252-85-86700/perusahaan-turki-rampungkan-kajian-enam-proyek-panas-bumi/(accessed 9 July 2016)

All geothermal permits (including Joint Operating Contracts) issued before the enactment of the 2014 Geothermal Law are still valid but are required to begin the exploitation stage by 31 December 2014.

5.2.2 Challenges in the Development of Indonesian Geothermal Industry

Specific challenges for investors in the geothermal space have included:

a) Difficulty in obtaining land permits, particularly where the resources are in a forest area;
b) Historic issues with inadequate tariffs, with an imbalance between upstream exploration risks and the utility-style economic returns, noting that the ultimate tariff depends on what capacity is determined as commercially feasible after exploration is finished;
c) Opposition from local communities;
d) The need for financing of significant upfront expenditure (with equity) for example, preliminary surveys, exploration and test drilling expenditure;
e) The poor quality of data provided on working areas prior to tender rounds, which in turn has increased the exploration risk of developers;
f) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, which makes for difficult access and difficult logistics on some sites; this may require the developer to fund infrastructure (e.g. access roads); and
g) Long lead times from exploration to production of seven to eight years.

The Government has tried a variety of FiT regimes for geothermal power generation, as one obstacle to the development of the industry has been the low pricing when compared to the high development costs. The latest FiTs, which were based on MoEMR Regulation No. 17/2014 to address long-standing concerns over the adequacy of geothermal tariffs, were as follows:

<table>
<tr><th rowspan="2">COD</th><th colspan="3">Ceiling Price (USD cents/kWh) for Geothermal Power Projects</th><th rowspan="2"></th></tr>
<tr><th>Region 1</th><th>Region 2</th><th>Region 3</th></tr>
<tr><td>2015</td><td>11.8</td><td>17.0</td><td>25.4</td><td rowspan="11">Region 1: Sumatra, Java, Bali

Region 2: Sulawesi, Kalimantan, Nusa Tenggara Timur (NTT), Nusa Tenggara Barat (NTB), Halmahera, Maluku and Papua

Region 3: Remote areas within Regions 1 or 2 that depend on power generation from diesel fuel power plants.</td></tr>
<tr><td>2016</td><td>12.2</td><td>17.6</td><td>25.8</td></tr>
<tr><td>2017</td><td>12.6</td><td>18.2</td><td>26.2</td></tr>
<tr><td>2018</td><td>13.0</td><td>18.8</td><td>26.6</td></tr>
<tr><td>2019</td><td>13.4</td><td>19.4</td><td>27.0</td></tr>
<tr><td>2020</td><td>13.8</td><td>20.0</td><td>27.4</td></tr>
<tr><td>2021</td><td>14.2</td><td>20.6</td><td>27.8</td></tr>
<tr><td>2022</td><td>14.6</td><td>21.3</td><td>28.3</td></tr>
<tr><td>2023</td><td>15.0</td><td>21.9</td><td>28.7</td></tr>
<tr><td>2024</td><td>15.5</td><td>22.6</td><td>29.2</td></tr>
<tr><td>2025</td><td>15.9</td><td>23.3</td><td>29.6</td></tr>
</table>

The ceiling price will be paid as the Year 1 tariff after COD, and then this tariff will increase over time. PLN is responsible for funding and constructing the transmission line. Further, MoEMR Regulation No. 17/2014 also allows existing geothermal projects to renegotiate their tariffs based on the new ceiling price after the completion of exploration and feasibility studies, as long as the PPA has been signed by the prescribed date. That date is between 31 August and 31 December 2014 depending on the status of the IUP - Geothermal and the assignment letter from the MoEMR.

Geothermal investment is characterised by a long lead time to commercial operations, and project financing is usually only available for the last few years of this process. This means that a typical geothermal project will require significant investor contributions in form of upfront equity. To assist with this, the GoI established the Geothermal Fund in the 2011 State Budget and had allocated IDR3 trillion (equivalent to USD 300 million) by the end of 2013. The Fund's aim was to make geothermal projects financially viable and bankable by providing high-quality information on greenfield geothermal sites verified by reputable international institutions to investors during the tendering process of new work areas to assist in mitigating the exploration risks of developers. Pursuant to the revised 2015 State Budget, responsibility for management of the Fund was transferred to PT SMI (see Chapter 1 and 3 for details of PT SMI) from *Pusat Investasi Pemerintah* ("PIP"). It is understood that, as of 2016, no funds have been disbursed from the Fund due to the inability of the MoF and PIP/SMI to decide upon an operational model.

Following the transfer of responsibility to PT SMI, the MoF has given policy directives stating that the current so-called Geothermal Support Fund should now be able to finance both the exploration and exploitation phases of geothermal projects.[62] It has also been stipulated that PT SMI should leverage the funds with other sources of funds from the private sector or international multilateral agencies.

Under the Indonesian model of geothermal development, the developer shoulders the exploration risk, and hence the obligation to fund the exploration phase. Whilst this may be tolerable for larger investors with strong balance sheets who are pursuing large projects, the approach is less likely to incentivise the development of smaller fields (below 30 MW), such as those in eastern Indonesia. The alternative approach, used in certain countries, is to assume part of the upfront exploration risk by providing support for this phase of activity by way of drilling insurance, direct grants or the use of revolving funds.

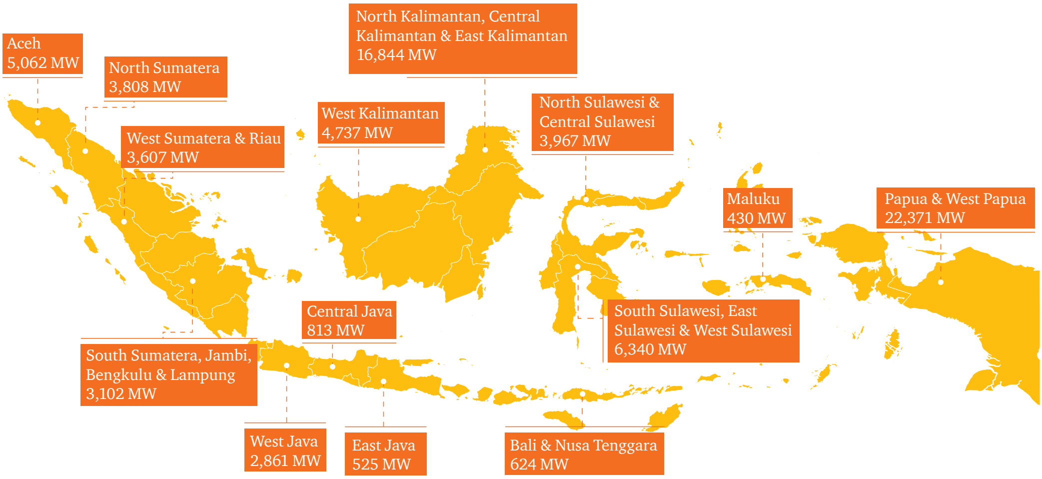
In early 2016 the Director for Geothermal Energy, Yunus Saifulhaq, indicated that the MoEMR would be introducing a Ministerial Regulation directed at reducing exploration risk, with the aim of attracting further geothermal investment. It was suggested that GSF would now also support a Government Drilling Scheme.[63] The drilling results and associated data would be independently certified and then used by the MoEMR to conduct a bidding process, with the winning bidder to make a payment for the data to the MoF, which would in turn reimburse PT SMI.

62 Government Supports for Geothermal Energy Development, Brahmantio Isdijoso, Directorate of Sovereign Risk Management, Directorate of Budget Financing and Risk Management, MoF, February 2016 Bali Clean Energy Forum
63 http://www.thinkgeoenergy.com/new-geothermal-legislation-in-indonesia-to-focus-on-reducing-risk/

5.3 Hydropower

Hydropower uses the energy from falling or flowing water to turn a water turbine and generate electricity. This can be a natural flow from a river ('run-of-river' plants) or an artificial flow resulting from a dam/reservoir or an irrigation canal. In 2014, Indonesia had an installed hydroelectric capacity of around 5,332 MW[64] out of a potential capacity of up to 75 GW (based on a hydropower potential study conducted in 1983) (see Figure 5.3), making it the most utilised source of renewable energy at present.[65] Potential hydropower sites are spread out across the country, with substantial potential for large-scale projects in the eastern part of Indonesia such as Kalimantan and Papua.

Figure 5.3 – Hydropower Potential in Indonesia



Source: RENSTRA DITJEN EBTKE 2015-2019

A Master Plan Study for Hydro Power Development in Indonesia conducted by Nippon Koei in 2011 found total hydropower potential of significantly less than 75 GW, at only 26,321 MW. Based on economic, social and environmental considerations, realistically, only 8 GW of additional hydropower is likely to be built in addition to the current existing power plants of 10,294 MW (projects in operation, in construction or planned). The report prioritised a list of candidate hydropower projects as follows:[66]

64 LAKIP KESDM 2015 p. 82.
65 RENSTRA KESDM 2015 – 2019, p. 42
66 2016 RUPTL p. 79.

No	Name	Type	Province	Cap. (MW)
1	Peusangan 1-2	ROR	Aceh	86
2	Jambo Papeun-3	ROR	Aceh	25
3	Kuet-1	ROR	Aceh	41
4	Muelaboh-5	ROR	Aceh	43
5	Peusangan-4	ROR	Aceh	31
6	Kuet-3	ROR	Aceh	24
7	Sibubung-1	ROR	Aceh	32
8	Seunangan-3	RES	Aceh	31
9	Teunom-1	RES	Aceh	24
10	Woyla-2	RES	Aceh	242
11	Ramasan-1	RES	Aceh	119
12	Teripa-4	RES	Aceh	185
13	Teunom-3	RES	Aceh	102
14	Tampur-1	RES	Aceh	330
15	Teunom-2	RES	Aceh	230
16	Padang Guci-2	ROR	Bengkulu	21
17	Warsamson	RES	Papua	49
18	Jatigede	RES	West Java	175
19	Upper Cisokan-PS	PST	West Java	1000
20	Matenggeng	PST	West Java	887
21	Merangin-2	ROR	Jambi	350
22	Merangin-5	RES	Jambi	24
23	Maung	RES	Central Java	360
24	Kalikonto-2	RES	East Java	62
25	Karangkates Ext.	RES	East Java	100
26	Grindulu PS-3	PST	East Java	1000
27	Kalikonto-PS	PST	East Java	1000
28	Pinoh	RES	West Kalimantan	198
29	Kelai-2	RES	East Kalimantan	168
30	Besai-2	ROR	Lampung	44
31	Semung-3	ROR	Lampung	21
32	Isal-2	RES	Maluku	60
33	Tina	ROR	Maluku	12
34	Tala	RES	Maluku	54
35	Wai Rantjang	ROR	NTT	11
36	Bakaru (2nd)	ROR	South Sulawesi	126
37	Poko	RES	South Sulawesi	233
38	Masuni	RES	South Sulawesi	400
39	Mong	RES	South Sulawesi	256
40	Batu	RES	South Sulawesi	271
41	Poso-2	ROR	Central Sulawesi	133
42	Lariang-6	RES	Central Sulawesi	209
43	Konaweha-3	RES	Central Sulawesi	24
44	Lasolo-4	RES	Central Sulawesi	100
45	Watunohu-1	ROR	South East Sulawesi	57
46	Tamboli	ROR	South East Sulawesi	26
47	Sawangan	ROR	North Sulawesi	16
48	Poigar-3	ROR	North Sulawesi	14
49	Masang-2	ROR	West Sumatera	40
50	Sinawar-2	ROR	West Sumatera	26
51	Sinamar-1	ROR	West Sumatera	37
52	Anai-1	ROR	West Sumatera	19
53	Batang Hari-4	RES	West Sumatera	216
54	Kuantan-2	RES	West Sumatera	272
55	Endikat-2	ROR	South Sumatera	22
56	Asahan 3	ROR	North Sumatera	174
57	Asahan 4-5	RES	North Sumatera	60
58	Simanggo-2	ROR	North Sumatera	59
59	Kumbih-3	ROR	North Sumatera	42
60	Sibundong-4	ROR	North Sumatera	32
61	Bila-2	ROR	North Sumatera	42
62	Raisan-1	ROR	North Sumatera	26
63	Toru-2	ROR	North Sumatera	34
64	Ordi-5	ROR	North Sumatera	27
65	Ordi-3	ROR	North Sumatera	18
66	Siria	ROR	North Sumatera	17
67	Lake Toba	PST	North Sumatera	400
68	Toru-3	RES	North Sumatera	228
69	Lawe Mamas	ROR	Aceh	50
70	Simpang Aur	ROR	Bengkulu	29
71	Rajamandala	ROR	West Java	58
72	Cibareno-1	ROR	West Java	18
73	Mala-2	ROR	Maluku	30
74	Malea	ROR	South Sulawesi	182
75	Bonto Batu	ROR	South Sulawesi	100
76	Karama	RES	South Sulawesi	800
77	Poso-1	ROR	Central Sulawesi	204
78	Gumanti-1	ROR	West Sumatera	16
79	Wampu	ROR	Sumut	84

RES: Reservoir, ROR: Run-off-River, PST: Pump Storage

The Government has planned that during 2015 - 2019, the development of Hydropower (including small hydro) (in MW) is as follows:

	2015	2016	2017	2018	2019
Hydro (including small hydro) non-state budget	222.0	899.0	326.0	477.0	527.0
Hydro (including small hydro) state budget - MoEMR	0.7	1.7	4.0	3.0	2.0
Hydro (including small hydro) special allocation fund	8.0	9.5	9.7	10.0	11.0
Construction of hydro (including small hydro) power plants	**230.7**	**910.2**	**339.7**	**490.0**	**540.0**

Source: RENSTRA KESDM 2015 – 2019

However, the strategic hydropower projects that the Government expects to be to be completed during 2015 – 2019 are as follows:

Planned Additions	Unit	2016	2017	2018	2019
Wampu	MW	**45.0**			
Meurebo – 2	MW	**56.0**			
Oksibil	MW	**1.0**			
Supiori	MW	**3.0**			
Ilaga	MW	**0.7**			
Rajamandala	MW		**47.0**		
Jatigede	MW				**110.0**
Asahan – 3	MW				**174.0**

Source: RENSTRA KESDM 2015-2019

Comparing the plan with the completion rate, it appears that the 2015 – 2019 plan to achieve the pre-determined hydropower installed capacity will be delayed.

5.3.1 Large-scale hydropower

As part of the 35 GW programme and PLN regular programme, several IPP projects are at the PPA negotiation stage, namely the Merangin (350 MW), Meurebo (56 MW) and Karangkates & Kesamben (137 MW) projects. The IPP Wampu hydro project (45 MW), Batang Toru (510 MW), Hasang (40 MW), Peusangan (83MW), Semangka (2 x 28MW), Bonto Batu (110MW) and Malea (2 x 45MW) are under construction. In addition, the 35 GW programme lists two PLN hydro projects at the construction stage, being the 4 x 260 MW Upper Cisokan pumped-storage plant in West Java and Asahan 3 (2 x 87 MW). Other than under the 35 GW programme, there are also construction projects under PLN's regular programme, namely Masang 2 (55 MW) and Jatigede (2 x 55 MW).

There are also nine further IPP hydro projects to be allocated by direct appointment totaling 413 MW under the 35 GW programme.

MoEMR Regulation No. 3/2015 regulates the ceiling levelised base price for large hydropower plants (with a capacity greater than 10 MW) as at the COD. The ceiling price varies according to the unit capacity, as described in the following tables. PLN may purchase power at a price above the benchmark price where it obtains approval from the MoEMR to do so.

Capacity	>10 - < 50 MW	50 - 100 MW	> 100 MW
Price (in cent USD/kWh)	9.00	8.50	8.00
Assumptions:			
Availability Factor (AF)	60%		
Contract Period	30 years		

Specific challenges for large-scale hydropower include:

a) The need for substantial amounts of land, of which the ownership may be unclear or subject to overlapping claims;
b) Overlapping permits (for example where small hydro permits have been issued on a section of a larger watercourse)
c) Environmental, resettlement, and flora and fauna issues; and
d) Permits for forest use.

5.3.2 Small-scale hydropower

FiTs for hydropower plants with a capacity of up to 10 MW are currently regulated under MoEMR Regulation No.19/2015 (which came into effect on 29 June 2015 and replaced MoEMR Regulation Nos.12/2014 and 22/2014). They are based on the voltage and the location of the plant, include all procurement costs for connection to the PLN network, and come into effect at COD in accordance with the PPA. Different FiTs are offered for small hydro plants using energy from river waterfalls and those using hydropower from reservoirs, dams or irrigation canals. The summary of FiTs for Hydroelectric Power Plants Utilising the Power of the Water Current or Waterfall in a River with a Capacity of Up to 10 MW is as follows:

No	Voltage of Electricity Network (Capacity of Power Plant)	Location/Region	Purchase Price (USD cent/kWh)		Factor F
			Year 1 - year 8	Year 9 - year 20	
1	Medium-voltage grid (up to 10 MW)	Java, Bali and Madura	12.00 x F	7.50 x F	1.00
2		Sumatra	12.00 x F	7.50 x F	1.10
3		Kalimantan and Sulawesi	12.00 x F	7.50 x F	1.20
4		West and East Nusa Tenggara	12.00 x F	7.50 x F	1.25
5		Maluku and North Maluku	12.00 x F	7.50 x F	1.30
6		Papua and West Papua	12.00 x F	7.50 x F	1.60
1	Low-voltage grid (up to 250 kW)	Java, Bali and Madura	14.40 x F	9.00 x F	1.00
2		Sumatra	14.40 x F	9.00 x F	1.10
3		Kalimantan and Sulawesi	14.40 x F	9.00 x F	1.20
4		West and East Nusa Tenggara	14.40 x F	9.00 x F	1.25
5		Maluku and North Maluku	14.40 x F	9.00 x F	1.30
6		Papua and West Papua	14.40 x F	9.00 x F	1.60

Source: MoEMR Regulation No. 19/2015

The Summary of FiTs for Hydroelectric Power Plants Utilising the Power from Reservoirs, Dams or Irrigation Channels of Multipurpose Construction with Capacity of Up to 10 MW is as follows:

No	Voltage of Electricity Network (Capacity of Power Plant)	Location/Region	Purchase Price (USD cent/kWh)		Factor F
			Year 1 - year 8	Year 9 - year 20	
1	Medium-voltage grid (up to 10 MW)	Java, Bali and Madura	10.80 x F	6.75 x F	1.00
2		Sumatra	10.80 x F	6.75 x F	1.10
3		Kalimantan and Sulawesi	10.80 x F	6.75 x F	1.20
4		West and East Nusa Tenggara	10.80 x F	6.75 x F	1.25
5		Maluku and North Maluku	10.80 x F	6.75 x F	1.30
6		Papua and West Papua	10.80 x F	6.75 x F	1.60
1	Low-voltage grid (up to 250 kW)	Java, Bali and Madura	13.00 x F	8.10 x F	1.00
2		Sumatra	13.00 x F	8.10 x F	1.10
3		Kalimantan and Sulawesi	13.00 x F	8.10 x F	1.20
4		West and East Nusa Tenggara	13.00 x F	8.10 x F	1.25
5		Maluku and North Maluku	13.00 x F	8.10 x F	1.30
6		Papua and West Papua	13.00 x F	8.10 x F	1.60

Source: MoEMR Regulation No. 19/2015

Regulation No.19/2015 also allows revisions to FiTs for small hydropower projects that have obtained a letter of appointment from the MoEMR under the previous regulation (MoEMR Regulation No. 22/2014).

The Director General of NREEC reported in 2016 that in the period of September 2014 to December 2015 there were proposals for 175 small-scale hydropower plants with an investment value of IDR10.94 trillion (USD783 million).[67] However, in early 2016 these proposals were at a standstill as PLN did not wish to sign a PPA with developers due to the anticipated losses for the SOE if using the published FiTs.[68] Proposals have been made to establish a renewable energy subsidiary of PLN or other SOEs to take on the role of off-taker for renewable energy projects and resolve this impasse.

Small hydropower plants are mostly targeted at rural electrification, with the largest potential in Java, Sumatra and Papua. In May 2016, PLN signed hydropower PPAs with:

- PT Bakara Energi Lestari (10 MW),
- PT Dempo Sumber Energi (13.4 MW),
- PT Green Lahat,
- PT Nusantara Indah Energindo,

67 Directorate General of NREEC website, accessed on Friday, 8 January 2016
68 Petromindo OGE, April 2016.

- PT Midigio, PT Sahung Brantas Energy,
- PT Malaka Guna Energi,
- PT Tropisindo Sumber Energi and PT Klaai Denden Lestari (totaling 21.2 MW),
- PT Uway Energy Perdana (7 MW) to support electricity need in Sumatera.[69]

Further in May 2016, PLN also signed small hydropower PPAs with:
- PT Tirta Mukti Lestari (PLTMH Cibuni – 3.2 MW),
- PT Lima Energi Lestari (PLTMH Pesantren 1 – 1.8 MW),
- PT Petro Hidro Optima (PLTMH Cikaengan – 5.1 MW),
- PT Cikaengan Tirta Energi (PLTMH Cikaengan 2 – 7.2 MW),
- PT Manha Daya Mandiri (PLTMH Cibuni Mandiri – 2 MW),
- PT Republika Mandiri Energi (PLTMH Cikandang – 6 MW) and
- PT Bangun Bumi Bersatu (PLTMH Cibareno 1 – 5 MW) in West Java and Banten Provinces to increase the rural electrification rate in those Provinces.[70]

Reportedly, the FiTs used in these PPAs are not based on MoEMR Regulation No. 19/2015 but rather based on PLN's Circular Letter No. 047/REN.01.01/DITREN/2016 which determined the hydro power tariff of USD0.07 – 0.08/kWh.[71]

Challenges for investment in small-scale hydro include:
a) A limit on foreign investor equity ownership. As outlined in Chapter 2, the most recent negative list detailed in PR No. 44/2016 sets certain limitations on foreign investment, as micro power plants (<1 MW) are closed for foreign investment and small power plants (1 – 10 MW) are open for foreign ownership up to a maximum of 49%;
b) The need to invest in transmission lines;
c) The requirement to submit a deposit certificate equal to 5% of the total investment amount. This is a significant burden for many investors due to needing to be funded in the earlier stages of projects;
d) The relatively high front-end investment costs, with smaller developers struggling to fulfil their 30% equity requirements. PPAs for mini hydro generally will not have a take-or-pay provision, so there is an off-take risk borne by investors;
e) Access to finance: with investment of USD2.0 - USD2.5M per MW required, typically the investment size is too small for project finance in Indonesia and is likely to require substantial collateral;
f) The quality of hydrological data;
g) Ongoing O&M by local communities;
h) Distances from equipment providers; and
i) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, making for difficult access and difficult logistics on some sites, resulting in higher transportation and delivery costs of equipment.

69 http://us.finance.detik.com/read/2016/05/30/124027/3220782/1034/pln-teken-18-kontrak-jual-beli-listrik-energi-terbarukan-1156-mw, accessed 19 June 2016.
70 https://www.aktual.com/tujuh-pembangkit-listrik-mikrohidro-ini-tandatangani-ppa-dengan-pln/, accessed 19 June 2016.
71 *Kontan, 8 Juni 2016, Energi Terbarukan ESDM Minta PLN Cabut Harga PLTMH.*

5.4 Bioenergy

Bioenergy refers to the renewable energy obtained from biomass to generate electricity and heat or to produce liquid fuels (e.g. biodiesel or bioethanol) for transport use. Biomass is the 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 by the decomposition of organic matter in the absence of oxygen. For example, biogas can be obtained from animal waste, POME or MSW. Bioenergy, particularly from biomass (e.g. wood fuel, charcoal, rice husks) has traditionally been utilised in Indonesia and plays an important role in rural areas where it is commonly used by households and small industry.

The potential of bioenergy for power generation in Indonesia is estimated to be 50 GW (33 GW for biomass (see Table 5.3) and 17 GW for biogas) with 1.8 GW of current installed capacity.[72] Most are off-grid. Biomass plants connected to the PLN electricity grid only have a total installed capacity of around 120 MW. At the inauguration of the Asian Agri POME Biogas plant in early 2016, the DGNREEC indicated that by 2018 the Government would oblige companies producing waste to utilise this waste. The intent of the policy was reported as encouraging the conversion of waste to energy, but it could also have the additional benefit, in certain cases, of avoiding the release of harmful methane gas into the atmosphere. The Government plans further growth in biogas and biomass plants, albeit more private-sector driven, but itself will be supporting the development of waste-to-power plants.

Table 5.3 - Potential Biomass Resources for Power Plants (in MWe)

No	Type of Waste	Sumatera	Kalimantan	Jawa-Bali-Madura	Nusa Tenggara	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 DITJEN EBTKE 2015 – 2019

As of 31 December 2015, biomass power plants with an installed capacity of 119.6MW have already been connected to the grid (see Table 5.4).

72 LAKIP EBTKE 2015, p. 38.

Table 5.4 - On-grid Biomass Power Plants

No	Company	COD	Type of Contract	Location	PLN Area	Type of Biomass	Contract (MW)
1	PT Riau Prima Energy	2001	Excess power	Riau	PLN Wilayah Riau	Palm waste	10.0
2	PT Listrindo Kencana	2006	IPP	Bangka	PLN Wilayah Bangka	Palm waste	5.0
3	PT Growth Sumatra 1	2006	Excess power	Sumatra Utara	PLN Wilayah Sumut	Palm waste	9.0
4	PT Indah Kiat Pulp & Paper	2006	Excess power	Riau	PLN Wilayah Riau	Palm waste	3.0
5	PT Belitung Energy	2010	IPP	Belitung	PLN Wilayah Babel	Palm waste	7.0
6	PT Growth Sumatra 2	2010	Excess power	Sumatra Utara	PLN Wilayah Sumut	Palm waste	10.0
7	PT Navigat Organic	2011	IPP	Bali	PLN Dist Bali	MSW	2.0
8	PT Navigat Organic	2011	IPP	Bekasi	PLN Dist Jabar	MSW	6.0
9	PT Growth Asia	2011	Excess power	Sumatra Utara	PLN Wilayah Sumut	Palm waste	10.0
10	PT Growth Asia	2012	Excess power	Sumatra Utara	PLN Wilayah Sumut	Palm waste	10.0
11	PT Navigat Organic	2012	IPP	Bekasi	PLN Dist Jabar	MSW	8.0
12	Harkat Sejahtera	2013	Excess power	Sumatra Utara	PLN Wilayah Sumut	Palm waste	10.0
13	Rimba Palma	2013	Excess power	Jambi	PLN Wilayah SBS	Palm waste	10.0
14	Austindo	2014	IPP	Belitung	PLN Babel Area	POME	1.2
15	PLN	2014	PLN Own	Gorontalo	PLN Sulutenggo	Corncob	0.4
16	Victorindo	2015	Excess power	North Sumatera	PLN Wilayah Sumut	Palm Waste	3.0
17	Sumber Organik	2015	IPP	Surabaya	PLN Wilayah Jatim	MSW	1.6
18	Meskom Agro Sarimas	2015	Excess Power	Riau	PLN Wilayah Riau	Palm Waste	10.0
19	Maju Aneka Sawit	2015	Excess Power	South Kalimantan	PLN Wilayah Kalimantan Selatan	POME	1.0
20	Sulajadi Sawit	2015	Excess Power	South Kalimantan	PLN Wilayah Kalimantan Selatan	POME	2.4
						TOTAL CAPACITY ON-GRID	**119.6**

Source: Statistik EBTKE 2015 and 2014, LAKIP KESDM 2015, RENSTRA DITJEN EBTKE 2015 - 2019 and PwC Analysis.

The Government has ambitious goals for additions to the on-stream capacity of bioenergy power plants from 2015 - 2019 as follows:

	2015	2016	2017	2018	2019
Installed capacity – beginning of year	**1,740**	**1,892**	**2,069**	**2,292**	**2,559**
Biogas	**46**	**43**	**76**	**101**	**126**
State budget	1	1	1	1	1
Private	45	42	75	100	125
Biomass	**77**	**76**	**87**	**97**	**107**
State budget	1	2	2	2	2
Private	76	74	85	95	105

	2015	2016	2017	2018	2019
Municipal waste	**29**	**58**	**60**	**69**	**80**
Private	1	1	1	1	1
State budget	28	57	59	68	79
Construction of bioenergy power plants	**152**	**177**	**223**	**267**	**313**
Installed capacity – end of year	**1,892**	**2,069**	**2,292**	**2,559**	**2,872**

Source: RENSTRA KESDM 2015 – 2019

In 2015, the municipal waste-to-energy projects that were in the process of implementation and to be completed in 2016 are as follows:

No	Final Disposal Area	Area	Capacity (MW)
1	Bantar Gebang**	Bekasi	10.0
2	Sumur Batu	Bekasi	3.0
3	Gedebage*	Bandung	7.0
4	Telaga Punggur	Batam	14.0
5	Muara Fajar	Riau	10.0
6	Bangklet Bangli	Bali	1.5
7	Benowo	Surabaya	9.0
8	Sukawinatan	Palembang	0.5
9	Babakan	Bandung	1.5
	Total		**56.5**

Source: RENSTRA KESDM 2015 – 2019 and PwC Analysis
* Bid winner announced in 2014 but implementation postponed due to social unrest
** Not yet been built and the contract was terminated by the DKI Jakarta Provincial Government

To encourage investment in power generation from bioenergy, IDR-denominated FiTs for biomass, biogas and municipal solid waste were issued under MoEMR Regulation No. 4/2012. However, the investments was not as high as expected, since the issuance of MoEMR No. 4/2012 due to the depreciation of the Rupiah against the USD and the increase in the price of biomass. As such, the FiTs for municipal waste-based power were increased under Regulation No. 44/2015 and the FiTs for biomass and biogas were increased under Regulation No. 27/2014. LAKIP KESDM 2015 indicated that the target of installed capacity of bioenergy power plants was not achieved, as in 2015 the additional installed capacity was only 27 MW compared to the plan of 152 MW. The low achievement was mainly due to low FiTs, since the exchange rate assumption used in MoEMR Regulation No. 27/2014 was IDR10,500/USD compared to an average rate of IDR13,392/USD in 2015. As a result, in August 2016 the Government revised this feed-in tariff for biomass and biogas in order to keep them fixed in USD terms (MoEMR Regulation No. 21/2016).

The FiT for municipal waste-based power is already denominated in USD. However, similarly to biomass and biogas, the development of municipal waste-based power plants is also slow. PR No. 18/2016 was issued to expedite the development of waste-based power plants in seven of Indonesia's larger cities (Jakarta, Bandung, Tangerang, Semarang, Surabaya, Surakarta and Makassar) in order to reduce the excess of waste accumulating at landfill sites and to produce electricity.

PLN is obliged to purchase power capacity of up to 10 MW from renewable energy sources. PLN can purchase electricity from bioenergy power plants either through PPAs or “excess power” agreements in cases where bioenergy producers generate electricity initially for their own use (e.g. in plantation estates). The sale of electricity from biomass and biogas to PLN is dominated by excess power schemes rather than IPP schemes, meaning the tariffs are lower and the investment is less attractive.

Summary of FiTs for IPP scheme Power Plants using Biomass is as follows:

No.	Location	Purchase Price (USD cent/kWh)				Factor F
		Capacity up to 20 MW		20 MW < Capacity ≤ 50 MW	Capacity > 50 MW	
		Low-voltage	Medium-voltage or High-voltage	High-voltage	High-voltage	
1	Java	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.00
2	Sumatera	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.15
3	Sulawesi	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.25
4	Kalimantan	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.30
5	Bali, Bangka Belitung, and Lombok	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.50
6	Riau, Nusa Tenggara and other islands	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.60
7	Maluku and Papua	16.00 x F	13.50 x F	11.48 x F	10.80 x F	1.70

Source: MoEMR Regulation No. 21/2016

Summary of FiTs for IPP scheme Power Plants using Biogas is as follows:

No.	Location	Purchase Price (USD cent/kWh)				Factor F
		Capacity up to 20 MW		20 MW < Capacity ≤ 50 MW	Capacity > 50 MW	
		Low-voltage	Medium-voltage or High-voltage	High-voltage	High-voltage	
1	Java	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.00
2	Sumatera	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.15
3	Sulawesi	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.25
4	Kalimantan	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.30
5	Bali, Bangka Belitung, and Lombok	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.50
6	Riau, Nusa Tenggara and other islands	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.60
7	Maluku and Papua	13.14 x F	10.64 x F	9.05 x F	8.51 x F	1.70

Source: MoEMR Regulation No. 21/2016

FiTs for Purchase of Excess Power by PLN from Biomass and Biogas Power Plants are as follows:

No.	Type of feedstock	Purchase Price (USD cent/kWh)			
		Capacity to 20 MW		20 MW < Capacity ≤ 50 MW	Capacity > 50 MW
		Low-voltage	Medium-voltage or High-voltage	High-voltage	High-voltage
1	Biomass	16.00	13.50	11.48	10.80
2	Biogas	13.14	10.64	9.05	8.51

Source: MoEMR Regulation No. 21/2016

The Summary of FiTs for Power Plants Using MSW is as follows:

Technology	Grid	Purchasing price (cent USD/kWh)		
		< 20MW	20 – 50MW	> 50MW
Sanitary landfill, anaerobic digestion or similar technology	High-voltage grid	16.55	N/A	N/A
	Medium-voltage grid			
	Low-voltage grid	20.16	N/A	N/A
Thermochemical technology	High-voltage grid	18.77	15.95	13.14
	Medium-voltage grid		N/A	N/A
	Low-voltage grid	22.43	N/A	N/A

Source: MoEMR Regulation No. 44/2015

Pertamina has indicated that it is working with partners to develop biogas from POME in the North Sumatra and Riau provinces. The North Sumatra project is reported to be in the Sei Mangkei Special Economic Zone, with biogas-to-electricity potential of 1.6 MW and with the tenant being the off-taker. This facility is due to come online in 2016. In Riau, Pertamina is working with a cluster of palm oil mills to develop a 10 MW facility due to come online in 2017.[73]

Asian Agri plans to build 20 biogas power plants by 2020. In 2015, Asian Agri built and began operating five biogas power plants to convert POME into power for its own use as well as selling the excess power to PLN.

In April 2016, PLN signed two PPAs, whereby PLN will purchase electricity from a 10 MW biomass power plant from Welcron Power Kalimantan and a 2 MW biogas power plant from Nagara Bio Energy, respectively, after the completion of the power plants in 2017. The electricity selling price is set according to MoEMR No. 27/2014.

Challenges for investment in bioenergy projects include:

a) The availability of biomass feedstock on a continuous and reliable basis;
b) The suitability of grid infrastructure or distance from grid connections;
c) The coordination required between PLN and various authorities (central and local);

73 *"Enhancing Bioenergy Utilisation to Improve Energy Security",* Andianto Hidayat, Gas, New and Renewable Energy Directorate, Pertamina 12 February 2016, Bali Clean Energy Forum

d) Permitting and licensing issues (land, water, environmental) and clarity at the local level on the associated fees and processes;
e) The availability of local EPC contractors with the right experience and skills; and,
f) The availability of spare parts and after-sales service.

Challenges for investment in MSW power plants have been found to include:
a) Delays in securing the PPA and off-take arrangements for electricity from MSW;
b) The insufficiency of feed-in tariffs for MSW and whether a share of tipping fees is required (in some cases, the Local Government is unwilling to pay sufficient tipping fees);
c) Concerns from Local Governments over management and responsibility for implementation of waste-to-energy plants due to a lack of experience in Local Government in waste-to-energy and lack of knowledge of power purchase mechanisms;
d) Negative sentiment from the local community over public health and safety issues;
e) Socio-economic concerns over livelihoods for waste pickers/scavengers; and,
f) The concerns of financiers over the use of new or unproven technologies.

5.5 Solar energy

In the context of power generation, the conversion of solar energy (sunlight) into electricity is done either directly using PV technology or indirectly using thermal technology as in the case of concentrated solar power ("CSP"). CSP involves using mirrors or lenses to concentrate the solar energy and convert this into heat. The heat is used to create steam, which drives a turbine to generate electricity.

The potential of solar energy in Indonesia averages approximately 4.8kWh/m^2 of solar insolation per day. The level of solar insolation varies across the Indonesian archipelago (see Table 5.5) but is regarded as offering good solar potential by international standard and represents a viable source of power for the population in remote or island locations that are off-grid.

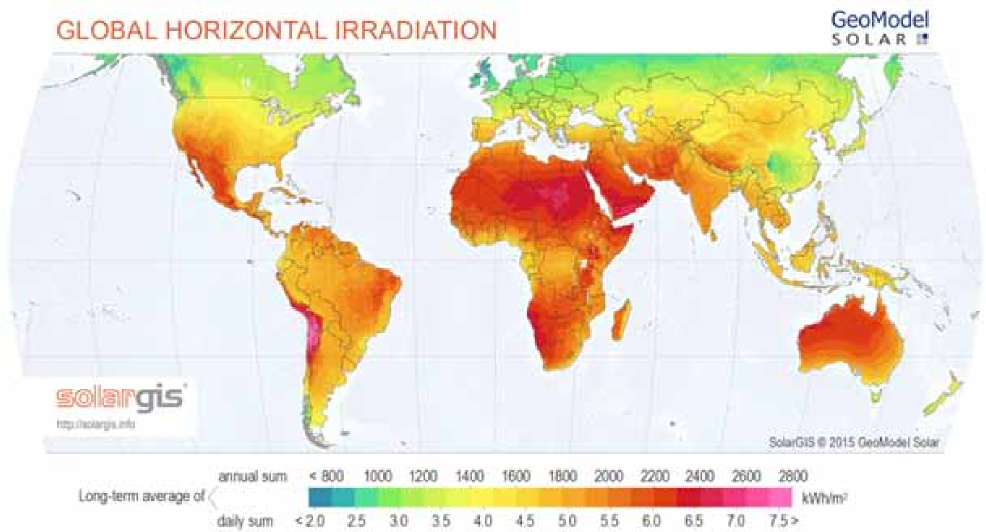
Table 5.5 - Solar Energy Potential in Indonesia

No	Regency/City Location	Province	Geographic Position	Average Insolation (kWh/m2/day)
1	Banda Aceh	Nanggroe Aceh Darussalam	4°15'N;96 °52'E	4.10
2	Palembang	South Sumatera	3°10'S;104°42'E	4.95
3	Menggala	Lampung	4°28'S	5.23
4	Jakarta	Special Capital Region of 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

No	Regency/City Location	Province	Geographic Position	Average Insolation (kWh/m2/day)
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	Menado	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 Tengarra (NT)	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: Statistik EBTKE 2014

A visual guide to the level of insolation in Indonesia compared to the rest of the world can be seen in the maps below.



Source: SolarGIS © 2016 GeoModel Solar

Current installed capacity is only about 80 MW, with the dominant portion of capacity being off-grid, mostly as solar home systems or small-to-medium off-grid systems (many of these are hybrid systems associated with small-scale diesel plants).[74] Indonesia had previously planned to increase this installed capacity to 260.3 MW by 2019 with an additional 189.3 MW over five years, which was a relatively modest target (see Table 5.6).

74 IEA (2015), Indonesia 2015, p. 126.

Table 5.6 - Solar On-stream Development Plan (in MW)

	2015	2016	2017	2018	2019
Installed capacity – beginning of year	**67.1**	**76.9**	**92.1**	**118.6**	**180.0**
Construction of solar power plants	**9.8**	**15.2**	**26.5**	**61.4**	**80.3**
Solar non-state budget	-	5.0	15.0	50.0	70.0
Solar state budget - MoEMR	2.8	3.0	4.0	3.5	2.0
Solar special allocation fund	7.0	7.2	7.5	7.9	8.3
Installed capacity – end of year	**76.9**	**92.1**	**118.6**	**180.0**	**260.3**

Source: RENSTRA KEDSM 2015 – 2019

LAKIP KESDM 2015 indicated that installed capacity for solar power plants had reached 85.2 MW, slightly higher than the planned level of 76.9 MW. This is mainly due to the completion of a 5 MW solar power plant in Kupang, East Nusa Tenggara, built by PT LEN Industri (see discussion below).

The solar PV development strategies set out in "The 1,000 Islands PV Development Programme" are used to reduce the use of diesel fuel and to increase the electrification ratio in remote islands where electricity is still generated using HSD/MFO fuel and fuel transportation is very expensive and complex. As such, the development will be focused on those remote areas, most of which are in the eastern part of Indonesia, which has a low electrification rate (below 60%) and no other sources of renewable energy where it will not increase the electricity production costs compared to the existing electricity systems.

Figure 5.4 – 1,000 Islands – PV Development Programme

Source: Moch. Sofyan (Head of New and Renewable Energy Division PT PLN (Persero)), "PLN - Solar PV Development Plant", Solar Workshop, Jakarta, 8 February 2013

Further to the 1,000 Islands PV Development Programme, the Government announced in February 2016 another target to achieve 5,000 MW of solar power capacity by 2020. The strategy for achieving this 5,000 MW Programme includes:

- Cooperation with the Financial Services Authority, MoEMR and the Local Government of ten Provinces.
- Develop "*Program Energi Terbarukan Listrik Desa*" with a target to electrify 10,300 villages which do not currently have electricity, by 2019.
- Subsidy granted to solar FiTs
- Developing regulations for hybrid PV, on-grid PV and roof-top PV.
- Developing a quality standard solar panel with qualified expert resources.

The planned distribution of 5,000 MW solar PV will be as follows:

- On-grid general scale – 1.5 GW
- Hybrid (diesel and PV) – 1 GW
- Government and private building – 0.5 GW (Rooftop PV)
- Industrial zone – 0.5 GW(Rooftop PV)
- Residential – 0.5 GW(Rooftop PV)
- Villages without electricity – 1 GW

In March 2016 it was announced that Pertamina would also assist with rural electrification under the Bright Indonesia Programme with the building of 1,000 MW of solar plants in areas without electricity and/or in eastern Indonesia. Pertamina also signalled its intention to build a 50 MW solar power plant in the Mandalika Special Economic Zone in West Nusa Tenggara.

5.5.1 Previous on-grid procurement

In July 2013 the DGNREEC announced details of tenders for a total of 140 MW of on-grid solar PV power stations across 80 locations, mostly in remote areas of Indonesia, based on MoEMR Regulation No. 17/2013 and DGNREEC Decree No. 979.K/29/DJE/2013 with regard to the Capacity Quota and Location for Solar Photovoltaic Power Plants in 2013. This was known as the PV IPP scheme, and provided FiTs of between USD0.25 - 0.30/kWh (depending on local content) for 140 MWp of tendered projects.

Only six business entities won the capacity quota tender with total capacity of 13 MW.[75] A summary of the capacity quota tender is as follows:

No.	Location	Capacity (MWp)	Developer	Selling Price (USD cent/kWh)
1	Kupang, East Nusa Tenggara	5	PT LEN Industri	25.00
2	Atambua, East Nusa Tenggara	1	PT Global Karya Mandiri	25.00
3	Kotabaru, South Kalimantan	2	PT Global Karya Mandiri	25.00
4	Gorontalo, Gorontalo	2	PT Brantas Adyawinsa KSO	22.95
5	Maumere, Ende	2	PT Indo Solusi Utama	24.98
6	East Sumba, East Nusa Tenggara	1	PT Buana Multi Technindo	24.98

75 RENSTRA EBTKE 2015-2019, p. 59.

Under a Supreme Court decision issued on 30 June 2014, but only made publicly available later in 2015, the tariffs and tender process set out in MoEMR Regulation No. 17/2013 are no longer valid, as the Supreme Court required the MoEMR to revoke Regulation No. 17/2013. Due to the striking down of MoEMR Regulation No. 17/2013, no tenders have been conducted since.

The Gorontalo facility achieved commercial operations in February 2016 and is operated by PT Brantas Abipraya (Persero), through its subsidiary PT Brantas Energy. The Sumba facility is being built by Conergy, PT Buana Surya Energi Persada and PT Indo Utama Solutions and is expected to start operating in the first half of 2016.

On 27 December 2015, President Joko Widodo inaugurated Indonesia's largest solar plant of 5 MW in Kupang, East Nusa Tenggara built by PT LEN Industri (Persero) (an SOE) under the IPP scheme at a reported cost of USD11.2 million.

5.5.2 New on-grid procurement

In July 2016 MoEMR approved MoEMR Regulation No. 19/2016, which replaced MoEMR Regulation No. 17/2013 and means that more Solar PV capacity will be tendered. This supports the 5,000 MW target announced in early 2016. The key provisions of the new regulation are as follows:

- At least 5,000 MW will be offered, starting with a Phase 1 of 250 MW.
- The Feed-in Tariffs will be fixed by province, and range from 14.5 USD c/kWh in Java (150 MW) to 25 USD c/kWh in Papua (2.5 MW) for the first phase. The tariffs may decline in subsequent phases. The tariff includes the cost of building transmission lines from the Solar PV Power Plants to the interconnection point.
- The tariffs are US Dollar-denominated but payable in Indonesian Rupiah at the Jakarta Interbank Spot Dollar Rate at the time agreed in the PPA. The PPA will valid for 20 years after the COD and may be extended.
- The procurement process will be overseen by MoEMR (using an online platform) and will be verified by the Task Force from the DGNREEC, DGE and PLN, while PLN is the signatory to the PPAs.
- The proposal verification will be undertaken on a first-come-first-served basis.
- Ongoing "Business-to-Business" procurement negotiations between private developers and PLN, where the PPA has not yet been signed, will be permitted to continue.
- Tariffs will be adversely affected if the project's local content is below the required levels (see section 2.2.3).
- Tariff reductions will be a linear function of the difference between the required local content levels and actual levels.
- For regions with capacity quotas offered of more than 100 MW, each capacity request by the Solar PV developer candidate should not exceed 20 MW; for regions with capacity quotas offered of between 10 MW and 100 MW, each capacity request by the Solar PV developer candidate should not exceed 20% of the quota offered; for regions with capacity quotas offered of up to 10 MW, there is no maximum limit to the capacity requested by each Solar PV developer candidate.
- Developers can obtain approval for a capacity quota a maximum of three times in the same region for each phase. However, if within one month the capacity quota is still available, the said developer can request further capacity in the same region.

The quotas allocated to each region and the FiTs for the first phase are as follows:

No	Region	Capacity Quota (MWp)	Purchase price (cent USD/kWh)
1	DKI Jakarta	150.0	14.5
2	West Java		
3	Banten		
4	Central Java and Jogyakarta		
5	East Java		
6	Bali	5.0	16.0
7	Lampung	5.0	15.0
8	South Sumatera, Jambi and Bengkulu	10.0	15.0
9	Aceh	5.0	17.0
10	North Sumatera	25.0	16.0
11	West Sumatera	5.0	15.5
12	Riau and Riau Islands	4.0	17.0
13	Bangka – Belitung	5.0	17.0
14	West Kalimantan	5.0	17.0
15	South and Central Kalimantan	4.0	16.0
16	East and North Kalimantan	3.0	16.5
17	North and Central Sulawesi and Gorontalo	5.0	17.0
18	South, South-east and West Sulawesi	5.0	16.0
19	West Nusa Tenggara	5.0	18.0
20	East Nusa Tenggara	3.5	23.0
21	Maluku and North Maluku	3.0	23.0
22	Papua and West Papua	2.5	25.0

The challenges of solar power plant development in Indonesia include:

a) The lack of appropriate regulatory support;

b) The need for greater Government, investor and stakeholder coordination on issues including: obtaining permits, land acquisition and grid conditions. For example, land availability with valid certification and suitability (e.g. not flood-prone), access to sites and a suitable grid should be confirmed prior to a bidding round;

c) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, which makes for difficult access and logistical challenges on some sites, resulting in higher transportation and equipment delivery costs;

d) Access to the right human resources/expertise and experience in solar PV technology;

e) In the case of small-scale hybrid PV systems, the management of issues associated with maintenance by PLN, the need for fuel-switching and the approval of off-grid tariffs by the local authority; and,

f) Limited technical experience within PLN teams to understand the implications of solar deployment on grid stability and how to manage risks.

5.6 Wind energy

Wind energy relies on the flow of air to turn a wind turbine, converting mechanical energy into electricity using a generator. Wind energy is regarded as consistent from year to year but can vary by the hour, day or season. The estimated potential of wind energy in Indonesia has historically been regarded as relatively small primarily because wind velocity in Indonesia is (in general) relatively low. The exception is in the eastern islands, where wind velocity can reach levels sufficient to power small-to-medium-scale wind turbines. The summary data from wind resources assessment and research for 153 sites is as follows:

Resource Potential	Wind Speed at 50 m, (m/s)	Wind Power Density, at 50 m, (W/m^2)	Number of Sites	Provinces
Lowest	< 3.0	< 45	66	West Sumatera, Bengkulu, Jambi, Central Java, South Kalimantan, West Nusa Tenggara, East Nusa Tenggara, South-East Sulawesi, North Sulawesi, Maluku.
Low (Small-Scale)	3.0 – 4.0	< 75	34	Lampung, Jogyakarta, Bali, East Java, Central Java, West Nusa Tenggara, South Kalimantan, East Nusa Tenggara, South-East Sulawesi, Central Sulawesi, North Sumatera, 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, Gorontalo.
High (Large-Scale)	> 5.0	> 150	19	Central Java, Jogyakarta, East and West Nusa Tenggara, South and North Sulawesi.

Source: RENSTRA DITJEN EBTKE 2015 - 2019

The ADB has more recently suggested that actual wind potential might be as high as 9 GW, although it should be noted that the areas in Indonesia with the most wind (i.e. eastern Indonesia) are also the least populated and have no existing transmission infrastructure to distribute electricity to larger population centres.[76]

76 ADB Paper No. 9, Summary of Indonesian Energy Sector Assessment December 2015. Soeripno Martosaputro and Nila Murti of WHyPGen also cite 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

The potential location for the commercial scale of wind energy in Indonesia is as follows:

Locations	Broad Area (ha)	Potential Energy (MW)
Sumatera	85,779	1,716
Banten and West Java	319,244	6,385
Eastern Java and Bali	305,231	6,105
Sulawesi	493,630	9,261
Eastern Nusa Tenggara	1,539,401	30,788
Maluku and Papua	385,920	7,718
	TOTAL	**61,973**

Source: Statistik EBTKE 2014

Within Java and Sulawesi, an initial study by BPPT-WHyPGen indicates that there is wind energy potential of around 970 MW distributed as follows:

No.	Locations	Potential Energy (MW)
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 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: Statistik EBTKE 2014

As at the beginning of 2015 installed wind power capacity was reported as 3.6 MW, of which 1.77 MW is connected to PLN's grid, while 1.84 MW is off-grid and is mainly for rural power supply. The largest wind farms are at Nusa Penida in Bali (0.735 MW) and at Sangihe and Selayar in Sulawesi (combined capacity of 0.54 MW). These generation facilities are on-grid and are the result of cooperation between MoEMR and PLN. The planned development of wind energy by the MoEMR appears to be very modest (see the table below) when compared to a number of private-sector developments which are beginning to take shape.

The Government has planned for additions to the on-stream capacity of wind power plants from 2015 – 2019 as follows:

	2015	2016	2017	2018	2019
Wind non-state budget	2.0	5.0	7.0	9.0	13.0
Wind state budget - MoEMR	0.5	0.2	0.5	1.0	2.0
Wind special allocation fund	0.2	0.5	0.8	1.0	1.2
Construction of wind power plants	**2.7**	**5.7**	**8.3**	**11.0**	**16.2**

Source: RENSTRA KEDSM 2015 – 2019

Several big areas from the initial study by BPPT-WHyPGen have now been developed such as Samas (Bantul), Sidrap and Jeneponto. Those substantial projects are now expected to go under construction in 2016.

In May 2015, the Samas 50 MW wind farm was launched by President Widodo, with PT UPC Renewables signing the first utility-scale wind PPA with PLN. The wind farm on the coast at Samas (Bantul - near Yogyakarta) is scheduled to commence construction in 2016 and to go into in operation in 2017, with investment being reported as being worth USD134 million. More recently, PLN signed a second PPA with UPC Consortium (UPC Renewables, PT Binatek Energi Terbarukan and Sun Edision Inc.) in August 2015 for the 70 MW Sidrap wind farm in South Sulawesi. This facility is being constructed after obtaining financial assistance amounting to USD120 million from the Overseas Private Investment Corporation in April 2016 so that it can come online in 2017.[77]

Asia Green Capital Partners Pte Ltd is currently developing 182.5 MW of wind farm projects in Indonesia, with 162.5 MW on the island of Sulawesi and 20 MW on the island of West Timor, through its subsidiary Indo Wind Power Holdings Pte Ltd.[78] The 62.5 MW Jeneponto 1 wind farm will be co-developed with IFC and will be connected to the South Sulawesi grid. A second farm, Jeneponto 2, with a capacity of 100 MW is also being considered.

PACE Energy, a joint venture between EREN Renewable Energy and CWP Energy Asia, is also considering wind farm investment in Indonesia and in August 2015 Pace Energy Pte Ltd. signed a Memorandum of Understanding ("MOU") with the MoEMR to develop a 150 MW wind farm in Lebak, Banten Province.[79]

The default base feed-in tariffs for small-scale wind power at IDR656/kWh (medium voltage) to IDR1,004/kWh (low voltage) are generally believed to be uncompetitive (even with incentive factors based on location) and are reportedly under review by the MoEMR. The ADB also reports[80] that the MoEMR is currently considering further incentives for wind power.[81]

77 www.upcrenewables.com/indonesia and Bisnis Indonesia 8 April 2016
78 www.agcp.com.sg
79 pace.co.id
80 ADB (2015). *op.cit.*, p. 33.
81 Article 2 of MoEMR Regulation No. 4/2012 on the Electricity Purchase Price by PLN from Power Plants Using Small and Medium Renewable Energy or Excess Power

Challenges in developing wind power investments include:

a) The lack of an established competitive feed-in tariff and an established regulatory framework;
b) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, making for difficult access and difficult logistics on some sites, resulting in higher transportation and delivery costs of equipment;
c) Concerns over 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 front-end investment costs;
f) The need to access existing MoF incentives, noting that projects require the importation of sophisticated equipment manufactured overseas;
g) The need for greater collaboration between all stakeholders including the Government, PLN and investors; and,
h) The need for on-grid wind farms to participate in the central PLN dispatch process.

5.7 Ocean energy

Ocean energy refers to the renewable energy obtained from the sea, either as mechanical energy from the tide and waves or thermal 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 deeper waters to generate electricity.

The potential Ocean Energy capacity in Indonesia is as follows:

No	Type	Theoretical potential (GW)	Technical Potential (GW)	Practical Potential (GW)
1	OTEC	57.0	52.0	43.0
2	Tidal	160.0	22.5	4.8
3	Sea Wave	510.0	2.0	1.2
	Total	727.0	76.5	49.0

Source: EBTKE Investment Opportunities November 2014

In 2015, Energy and Mineral Resources Minister Sudirman Said indicated that Indonesia would encourage the use of energy potential from the sea as part of the Government's marine development policy.[82]

82 Jakarta Post, 3 June 2015

The MoEMR currently has two pilot projects underway, one at Nusa Penida and another at Nusa Tenggara. The MoEMR's plan is that 1 MW of ocean energy pilot plants should be ready by 2019.[83]

Pertamina has committed to developing 3 MW of ocean energy by 2019 and in February 2015 signed an MOU with Akuo Energy to collaborate on renewables, including on OTEC.[84]

In August 2015 PLN signed an MOU with SBS International Ltd ("SBS") to develop ocean energy in the Alas Strait, Lombok Strait and Badung Strait with capacities of 12 to 140 MW at a reported cost of USD350 million.[85] SBS has been assessing the potential of ocean energy in Indonesia since 2013. In April 2016, it was announced that SBS would partner with Atlantis Resources Ltd, an AIM (UK)-listed, but Singapore-based tidal power company, to establish a joint venture to develop a 150MW tidal stream site in Indonesia in several stages. The investment costs have been estimated at USD750 million, with the feasibility study already done by SBS and the project supported by a 25-year PPA with PLN.[86]

An Indonesian Ocean Energy Association exists, and in 2013 a draft road map for ocean energy regulation was released with their involvement. In 2016, with the support of the UK and Indonesian governments, the South East Asian Marine Energy Centre was established in Indonesia.

Challenges for ocean energy in Indonesia include:

a) The domestic availability of technologies and the early state of pilot projects and evaluations in the country;
b) Geographical distances, the logistics of locations and absence of infrastructure; and,
c) The need to develop a market and the economics of ocean energy electricity generation.

83 RENSTRA KESDM 2015 – 2019 page 137. MoEMR, Agency for the Research and Development of Energy and Mineral Resources, Bali Clean Energy Forum 12 February 2016, Susilohadi Susilohadi
84 Pertamina press release dated 19 August 2015.
85 www.acnnewswire.com August 20, 2015
86 www.atlanticresourcesltd.com/atlantis-announcements.html 2016 April 4

6. Taxation Considerations

Photo source: PT Paiton Energy

6.1 Overview

This chapter provides a general overview of the tax issues relevant to private investors in power generation projects in Indonesia (with specific tax issues for renewable energy projects set out in Section 6.4). These comments focus on the tax regime relevant to equity investors but also touch upon the taxes likely to be encountered by asset constructors, capital equipment suppliers, employees and financiers.

The taxes relevant to power generation projects in Indonesia fall under the following general headings:

a) Income Tax due on in-country profits;
b) (Income Tax) withholding tax (WHT) obligations generally due on service, royalty and interest payments;
c) (Income) Tax due on capital gains such as those arising on asset sales and upon any project divestment;
d) Value Added Tax (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;
f) Other taxes including:
   i) Import taxes;
   ii) Various regional taxes; and
   iii) Taxes due on the ownership of land and buildings.

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 oil and gas and mining sectors, this Income Tax regime is largely that which applies to general business activities. That is, there are very few power-sector-dedicated Income Tax rules and, in particular, there are no provisions allowing for tax stability over the life of a power investment. As discussed below, this could mean that the tax regime is deficient in a number of key areas, at least from a private power project investor's perspective.

Indonesia's general Income Tax arrangements are, internationally speaking, quite conventional and offer rates of tax that are quite competitive even on a regional basis.
The principal features include the following:

a) A flat rate of Income Tax due at (currently) 25% of taxable profits. This rate will however move 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% and other conditions may also be able to enjoy a further 5% reduction of this rate to 20%;
b) A general entitlement to deduct/depreciate most spending connected to income generation;
c) A largely unrestricted entitlement to deduct financing costs (although see comments below);

d) An increasing focus on transfer pricing (TP) compliance and so the potential for TP related adjustments;
e) A five year tax loss carry forward entitlement; and
f) A document intensive tax administration environment with automatic tax audits before the payment of any tax refunds.

Overall, the taxable income calculation largely follows the conventional accounting profit with largely conventional adjustments for various timing and permanent differences (although see below on the ISAK 16 accounting rules). The regime is however 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.

One recent development is the likelihood of PLN imposing a 1.5% "withholding" of (Article 22) Income Tax on payments made to IPP companies (given PLN's status as a state owned enterprise) with effect from 1 January 2016. The 1.5% tax (if applied) should be creditable to the IPP company and so represent a cash flow concern only.

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 IPP) having to book their arrangements as being in the nature of a lease or (more likely) as a service concession. This treatment could have a significant impact on the books of the IPP if, for example, in a service concession arrangement, the power asset is reclassified as a financial asset.

There is no formal guidance on the tax impact of these accounting changes from the Indonesian Tax authorities. In a general sense, whilst 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 should be monitored.

Deductibility Issues

Whilst 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 pricing agreed between parties under a "special relationship" where that pricing was not considered to be arm's length. A special relationship is deemed to exist at a relatively low 25% common equity threshold. The tax authorities have also recently enhanced the documentation requirements to support such pricing. This reflects Indonesia's increasingly aggressive monitoring of TP concerns;

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

c) *Pre-establishment expenses*: whilst not specifically denied, the general tax rules do not easily accommodate 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 in excess of 12 months. The law then allows depreciation to the extent that the spending relates to tangible assets and amortisation to the extent that it relates to intangible assets.

   Depreciable costs include all expenditure incurred to purchase, install and construct an asset, which generally extends to interest incurred during the construction period where that interest is construction related.

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

	Effective Life max. (years)	Straight Line Rate (%) p.a.	Double Declining Rate (%) p.a.
i)	4	25	50
ii)	8	12.5	25
iii)	16	6.25	12.5
iv)	20	5	10

   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 double declining 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 approval, commencement can be delayed until operations begin;

e) *Land and buildings*: while "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%. The option to use the double declining rate is not available. Land cannot be depreciated and also does not usually include buildings. Where assets are attached to the ground and cannot be moved without being dismantled they may constitute buildings. Uncertainty can therefore exist regarding the classification of tangible assets connected to land such as roads, fences, wharfs, reservoirs and pipelines;

f) *(Thin capitalisation) debt:equity requirements*: on 9 September 2015 the Minister of Finance issued Regulation No. 169/2015 which introduced a general debt and equity ratio ("DER") limitation of 4:1 for Income Tax purposes. MoF 169 first applies 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. There are preliminary debt and equity definitions provided. MoF 169 does however provide an exemption from the DER rules for certain industries including for those involved in "infrastructure" albeit without an "infrastructure" definition. Implementing regulations on the DER arrangements were outstanding at the time of writing. It was therefore not clear whether IPP activity is to be excluded from the DER limits.

g) *payments of non-cash employment benefits*: see more detailed comments below under 6.2.5 Personnel taxes.

6.2.2 Withholding Tax ("WHT")

In an Indonesian context WHT constitutes 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 and will typically be at 2% of the relevant payment. In these cases the service provider would be required to submit an annual Indonesian Income Tax return and credit the WHT against the annual tax liability, and be entitled to a refund of any excess.

Types of payments subject to creditable/non-final WHT include:

a) Payments to residents for the rent of moveable property (rate of 2%);
b) Payments to residents for consulting, management or technical services (rate of 2%);
c) Payments to residents constituting royalties (rate of 15%).

WHT is also collected on a "final tax" basis. This WHT is still calculated as a percentage of the gross payment, but there is no additional Income Tax due from the recipient on that income and also no refund potential (i.e. irrespective of the actual profit derived from the payment).

Engineering, procurement and construction ("EPC") related services are subject to this "final tax" regime via a WHT mechanism by the relevant IPP. Depending upon the structure and the EPC provider's construction qualifications the WHT rates vary between 2% and 6%.

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

a) Payments to residents for the rent of certain non-movable property (rate of 10%);
b) Payments to non-residents for most services as well as for interest and royalties (rate of 20% before any treaty relief);
c) Dividends paid to non-resident investors from the profits from operating power assets (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 "profits" made from the sale of assets are generally simply treated as income.

An exception is for the sale of assets made by non-residents. In this case, Income Tax is currently limited to the sale of shares in non-public Indonesia entities by a non-resident with the Income Tax effectively being due at the flat rate of 5% of transaction proceeds (i.e. irrespective of whether any economic profit has been made).

Further, for the sale of shares in Indonesian entities listed on the Indonesian stock exchange (IDX) Income Tax is due at the flat rate of 0.1% of transaction proceeds. To be eligible for this rate, founder shareholders must pay tax at 0.5% of the market price of their shares upon listing otherwise gains on subsequent sales are taxed under normal rules.

6.2.4 Value Added Tax ("VAT")

Indonesia imposes a broad based VAT currently set out pursuant to 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.

Indonesia's VAT system is quite conventional, with VAT required to be charged (as output VAT) on the value of most supplies of goods and services made within Indonesia and with each person being charged such VAT (as input VAT) being entitled to a credit, providing that this person themselves incurs VAT on its 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 outcome is discussed further below.

6.2.5 Personnel taxes

Income Tax on remuneration

Employment related cash remuneration is subject to Indonesian Income Tax at (a maximum) rate of 30% for resident employees, or at a (flat) rate of 20% for non-residents. Non-cash remuneration (or benefits in kind) is typically treated as non-taxable in the hands of the employee, but with the cost of the benefit being non-deductible to the employer.

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

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

Social Security contributions

Indonesian employment arrangements require both the employer and employee to make contributions to a number of schemes (see details in the table below). These schemes apply to all employees (now including expatriates).

A new social security scheme, known as the Social Security Agencies or *Badan Penyelenggara Jaminan Sosial* ("BPJS"), replaced the former Jamsostek scheme (which generally did not apply to expatriates) from 1 January and July 2015 for local employees and expatriates respectively.

The BPJS can be summarised as follows:

Insurance component	Agency		Scope	Deadline to register	Contribution rate
	Previous	New			
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.	Expatriate employees are required to be registered from 1 July 2015	Due at 7.74% of the "fixed monthly regular income" ("FMRI") with 5.74% contributed by the employer and 2% contributed by the employee
Health	• PT Jamsostek • PT Askes • Ministry of Health • Ministry of Defence, National Army, Police Department	BPJS for health insurance (*BPJS Kesehatan)*	Basic health insurance	Employees must register their employees from 1 January 2015	Due at 5% of FMRI but only up to IDR4,725,000 with 4% contributed by the employer and (starting from 1 July 2015) 1% contributed by the employee (currently 0.5%)

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 type of goods in question;

b) *VAT*: this is due at 10% of "the Import Duty inclusive" 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	0%
Transformers	Up to 10%
Electricity Transmission Cables	Up to 10%

Master list exemption – Import Duty

A concession (known as a "master list") is generally available for all BKPM licensed investments and provides an exemption from the Import Duty otherwise applying on imports of "machines, goods and materials" used for the establishment or development of a facility used to produce goods (which includes 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).

Customs exemption – 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 is now sought from BKPM.

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 those with ASEAN, Australia, New Zealand, China, India, Korea, Japan and Pakistan.

VAT exemption – strategic goods

Capital goods (being plant, machines and equipment but not spare parts) are considered to be "strategic goods". Under GR No.12/2001 (as amended by GR No.81/2015 and MoF Regulation No.268/2015) a VAT exemption is available for the importation of strategic goods where the goods are used to produce VAT-able goods.

As indicated above pursuant to GR No.81/2015, the supply of electricity is VAT-able but is exempted from VAT as a "strategic good" (except for supplies to households above 6600 watts). Therefore, even though power producers (including PLN) are generally VAT-exempt, a VAT registration entitlement exists and this generally allows access to the VAT exemption on imported capital goods (and, starting on 1 January 2016, VAT registration may effectively be made mandatory for IPPs even though electricity supplies remain VAT exempt).

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 exemption - 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 be available – see Section 6.4 for further discussion.

VAT for O&M services

The provision of Operations and Maintenance (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).

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 taxing powers were transferred exclusively to Indonesia's Provinces and Regions. These arrangements are currently set out in Law No.28/2009 (partially replaced by Law No.23/2014) which provides a closed list of regional taxes and maximum rates of tax. Each tax is subject to local implementation.

A summary of the regional tax arrangements is as follows:

<table>
<tr><th colspan="2">Type of Regional Tax</th><th>Maximum Tariff</th><th>Current Tariff</th><th>Imposition Base</th></tr>
<tr><td colspan="5">A. Provincial Taxes</td></tr>
<tr><td rowspan="5">1</td><td rowspan="5">Taxes on motor vehicle and heavy equipment</td><td rowspan="5">10% p.a.</td><td colspan="2">Non-public vehicles</td></tr>
<tr><td>1% – 2% for the first private vehicle owned</td><td rowspan="4">Calculated with reference to sales value and a weight factor (size, fuel, type, etc.) Government tables will be published annually to enable calculation.</td></tr>
<tr><td>2% – 10% for the second and more private vehicle owned</td></tr>
<tr><td>0.5% – 1% public vehicles</td></tr>
<tr><td>0.1% – 0.2% heavy equipment vehicle</td></tr>
</table>

Type of Regional Tax		Maximum Tariff	Current Tariff	Imposition Base
2	Title transfer fees on motor vehicles, above-water vessels and heavy equipment	20%	Motor vehicle	
			20% on first title transfer	
			1% on second or more title transfer	
			Heavy equipment	
			0.75% on 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 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 1.5% personal use	Sales value of electricity (power bill)
6	Tax on non-metal mineral and rock (formerly 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 required to evidence transactions. This includes the transfer 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 thus it can be substantial.

In Indonesia, however, Stamp Duty is due at nominal values, typically less than USD1, and thus is rarely a concern.

6.3 Issues for conventional power generation

6.3.1 Income Tax

As indicated, the tax arrangements relevant to Indonesia's power generation sector rely heavily on the general tax rules. This is unlike the arrangements that have historically applied to other large capital intensive projects, such as in the natural resources sector. There is also uncertainty around whether the tax arrangements will be impacted by the introduction of ISAK 8 or ISAK 16 (see discussion of Accounting Consideration in Section 7.1).

These issues aside, the commercial profile of a power project is generally more analogous to a large natural resources project than (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 often involving the establishment of relationships with multiple investing parties, the completion of detailed reviews and modelling of project viability, 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-Government) financing requirements;
c) A relatively long but non-volatile pay-back period with potentially only one customer and pricing pegged only to key operational costs;
d) A high level of economic sensitivity to the speed at which tax free cash can be generated to stakeholders and so the considerable relevance of depreciation and amortisation rates, capitalisation policies including in relation to interest expenditure, and depreciation classifications (i.e. land, buildings, other tangible assets, etc.).

Specific issues on these points which can arise under Indonesia's current tax regime include:

a) The lack of certainty around deductions for 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 (unless the new 4:1 DER applies-see above);

c) the potential for deductions to be lost due to a 5 year tax loss carry forward limitation; and
d) the incremental project costs arising from a VAT exemption on electricity supplies (see above).

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".

Quite importantly, where a supply is exempt from VAT the Input VAT incurred by that supplier will not be creditable. As such, for a power project in Indonesia making only supplies of electricity, all input VAT of that project will essentially become an outright cost to the project (although the VAT itself should be tax deductible). This is quite different in an economic sense to instances in which Input VAT is creditable and so constitutes a cash flow concern only.

In a general sense therefore, and assuming an Income Tax rate of 25%, the after-tax financial impact as a result of being a VAT exempt supplier is (in a broad based VAT environment) potentially up to 7.5% project costs (i.e. 10% VAT x (1 – 0.25% tax rate)). This potential cash impact therefore makes the availability of VAT relief on capital imports (such as those highlighted above) quite critical.

6.4 Taxation issues for renewable power generation

6.4.1 State revenues and taxes – geothermal regimes

The "old" geothermal regime was covered under a Joint Operating Contract ("JoC") framework introduced via Presidential Decree ("PD") 45/1991 (an amendment of earlier PD No.22/1981) whereby PERTAMINA (now PGE) and its contractors could undertake an integrated geothermal and power activity. That is, they could explore and exploit a geothermal source, build power plants and sell electricity to PLN and other consumers. PERTAMINA (now PGE) was responsible for managing the operations, while the Contractor was responsible for producing geothermal energy (i.e. steam), converting the steam into electricity and delivering steam and/or electricity.

From a tax perspective, a JoC is subject to a "*lex specialis*" arrangement within the JoC itself which generally outlines how to calculate net operating income which is then subject to a 34% tax. The 34% tax (generally called the "Government Share") is considered an "all inclusive" payment which is assumed to discharge the Contractor from other tax obligations including Income Tax, VAT, import taxes and land and buildings tax otherwise due under a normal tax regime.

Geothermal Law No.27/2003 (the 2003 Geothermal Law) however removed the all-inclusive rate of 34% and, under Geothermal Law No.21/2014, there are no (at least as yet – see below) specific tax regulations for geothermal activities. This means that the prevailing tax laws and regulations should apply for non-JoC geothermal projects. This also means that most of the Income Tax issues outlined in earlier sections of this chapter will also apply for all non-JoC geothermal projects (that is, projects licensed since the 2003 Geothermal Law was enacted).

On this basis, profits from both the geothermal/steam and power generation activities (noting that geothermal projects are now licensed on a disaggregated basis) are taxable at the standard rate of 25%.

6.4.2 VAT on geothermal projects

Steam generated from geothermal activity is considered to be a product of mining, excavation or drilling taken directly from the source. Under the prevailing VAT rules the supply of steam is therefore VAT exempt. This means that, under the post-2003 arrangements, input VAT related to supplies of both steam and electricity would not be creditable irrespective of whether connected to the steam or power generation activities (the VAT should instead be deductible).

This also contrasts with JoC arrangements, where VAT was generally reimbursable. Procedures on 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 Directorate General of Tax (DGT) circulated a draft GR on the proposed Income Tax arrangements for the (non-JoC) geothermal sector. Key points outlined in the draft GR included:

a) That the tax calculation will generally follow the prevailing Income Tax Law. An exception however could be an extension of the tax loss carried forward (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 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. These include:

a) *GR No.18/2015 (as amended by GR No.9/2016)*: this provides Income Tax incentives which include:
    i) A reduction in taxable income of up to 30% of qualifying expenditure on fixed assets (including land). The reduction is prorated at 5% over 6 years from commercial production;
    ii) An extended tax loss carry-forward period of up to ten years;
    iii) Accelerated depreciation and amortisation rates; and
    iv) A maximum dividend WHT rate of 10%.

    GR No.18 indicates that it applies to IPPs involved in "renewable energy".
b) *MoF Regulation No.177/2007*: this provides an exemption from Import Duty on the import of goods used in geothermal business activities". This is subject to the business entity having received a geothermal work area, a preliminary survey data or an IUP;

c) *MoF Regulation No.142/2015*: this provides an Import VAT exemption facility for geothermal projects in both the exploration and exploitation phases; and
d) *MoF Regulation No.21/2010*: this provides an Article 22 exemption for imports by IPPs involved in renewable energy.

A more substantial Income Tax "holiday" incentive applies for taxpayers operating in a "Pioneer Industry". Pursuant to MoF Regulation No.159/2015 such investors may be entitled to a CIT reduction of 10 - 100% for 5-15 years. The MoF can extend this to 20 years if the project is deemed to be in the national interest. The application process is centralised through the BKPM and ends on 15 August 2018.

Qualifying criteria include:
a) That the business is in a "pioneer industry" which includes economic infrastructure (other than those constituting PPP projects);
b) That the project involves a capital investment of at least IDR1 trillion;
c) That the investor deposits at least 10% of the total capital investment with an Indonesian bank which cannot be withdrawn prior to the realization of the investment;
d) That the project is carried out through an Indonesian legal entity established after 14 August 2011; and
e) That the taxpayer satisfies the DER stipulated in a separate MoF regulation.

MoF-159 removed "renewable energy" from the definition of pioneer industries but continues to allow "infrastructure" projects. It is therefore not clear whether renewable energy IPPs could still qualify for this incentive. In our view the GR No.18 incentive (see above) is likely to be more suited for renewable projects.

7. Accounting Considerations


Photo source: PT Paiton Energy

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 will need to account for their activities.

7.1.1. Arrangements that may contain a lease

PSAKs require that arrangements that convey 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 of wind or solar farms or biomass plants might be contracted to a single party under a PPA.

Pursuant to Interpretasi Standar Akuntansi Keuangan ("ISAK") 8 - Determining Whether an Arrangement Contains a Lease (equivalent to International Financial Reporting Interpretation Committee (IFRIC) 4), guidelines are provided on how to determine when such an arrangement might constitute a lease.

Once such a determination is reached, the arrangement must then be classified as either a finance or operating lease according to the principles set out in PSAK 30 - Leases (equivalent to IAS 17). In this regard a lease that conveys the majority of the risks and rewards of operation is treated as a finance lease. A lease other than a finance lease is treated as an operating lease.

The classification is significant for the following reasons:
a) a lessor in a finance lease would "derecognize" its generating assets and would instead recognise a finance lease receivable;
b) a lessee in a finance lease would recognise a fixed asset and a corresponding lease liability rather than account for the PPA as an executory contract.

Classification as an operating lease therefore leaves the lessor with the fixed asset on its balance sheet and the lessee with an executory contract.

IFRS in relation to arrangements that may contain a lease will change further due to the ongoing International Accounting Standards Board ("IASB") project on leases. As PSAKs are likely to reflect future changes in IFRS reporting, entities will need to monitor the activities of the IASB in this area.

PPAs

It can be difficult to determine whether a PPA constitutes a lease in this sense. For instance, even if the purchaser takes all or substantially all of the output from a specified facility, this does not necessarily mean that the purchaser is paying for the "right to use the asset" rather than for its output pursuant to ISAK 8. If the purchase price is a "fixed per unit of output" or equal to the "current market price at the time of delivery", the purchaser is presumed to be paying for the output rather than leasing the asset.

There have been some debates over the meaning of "fixed per unit of output" in ISAK 8 and two approaches have emerged in practice. "Fixed per unit of output" is interpreted by some entities in a manner that allows for no variability in pricing whatsoever over the entire term of the contract (i.e. fixed equals fixed). However, other entities have concluded that the fixed criterion is met if, at the inception of the arrangement, the purchaser and seller can determine what the exact price will be for every unit of output sold at each point in time during the term of the arrangement (i.e. fixed equals predetermined). There is support for both views, and the interpretation of "fixed" is an accounting policy election. The accounting policy should be disclosed and applied on a consistent basis to all similar transactions.

The "current market price at the time of delivery" criterion is narrowly interpreted. For example, arrangements that include caps/floors would not be considered to reflect the current market price at the time of delivery because the price at delivery might be different from the spot market price.

7.1.2 Service concession arrangements

PPPs are an arrangement whereby Governments attract private sector participation in 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 may construct the infrastructure (a power-generating plant in this instance) then maintain and provide 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.

ISAK 16 applies to arrangements where the grantor (the Government or its agents) controls or regulates what 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 arrangements will, in this context, be a power plant constructed on a Build-Own-Operate-Transfer 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 to recognise the rights received under a service concession arrangement are:

a) Financial asset – 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 asset – 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 payments are contingent on usage.

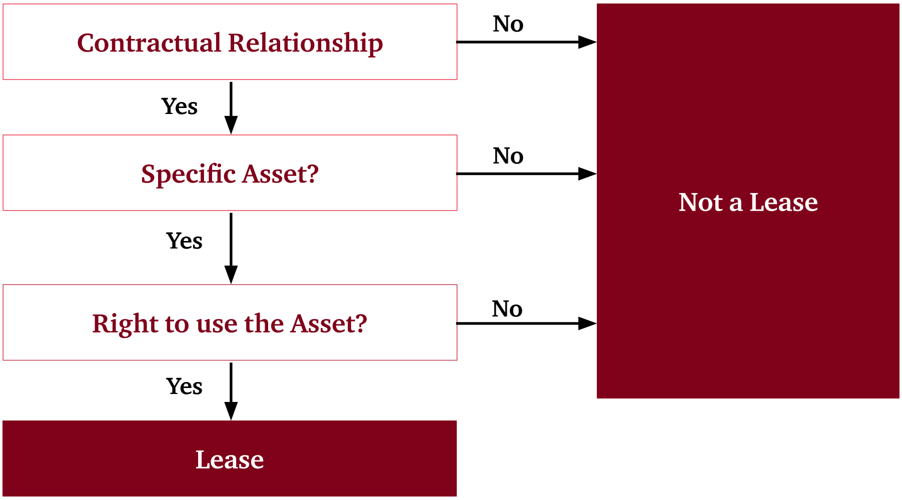
Arrangements between Governments and service providers are generally complex. Detailed analysis of the specific arrangement is necessary to determine whether the arrangement is within the scope of ISAK 16 and whether the financial asset or intangible asset model should be applied. Some complex arrangements may have elements of both models for the different phases. It may be appropriate to account separately or each of the elements of the consideration.

Once within the scope of ISAK 16 the appropriate accounting model may not always be obvious. Entities should be analysing arrangements in order to draw conclusions on whether these are within the scope of the interpretation and whether the arrangement falls under the financial asset or intangible asset models. 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.

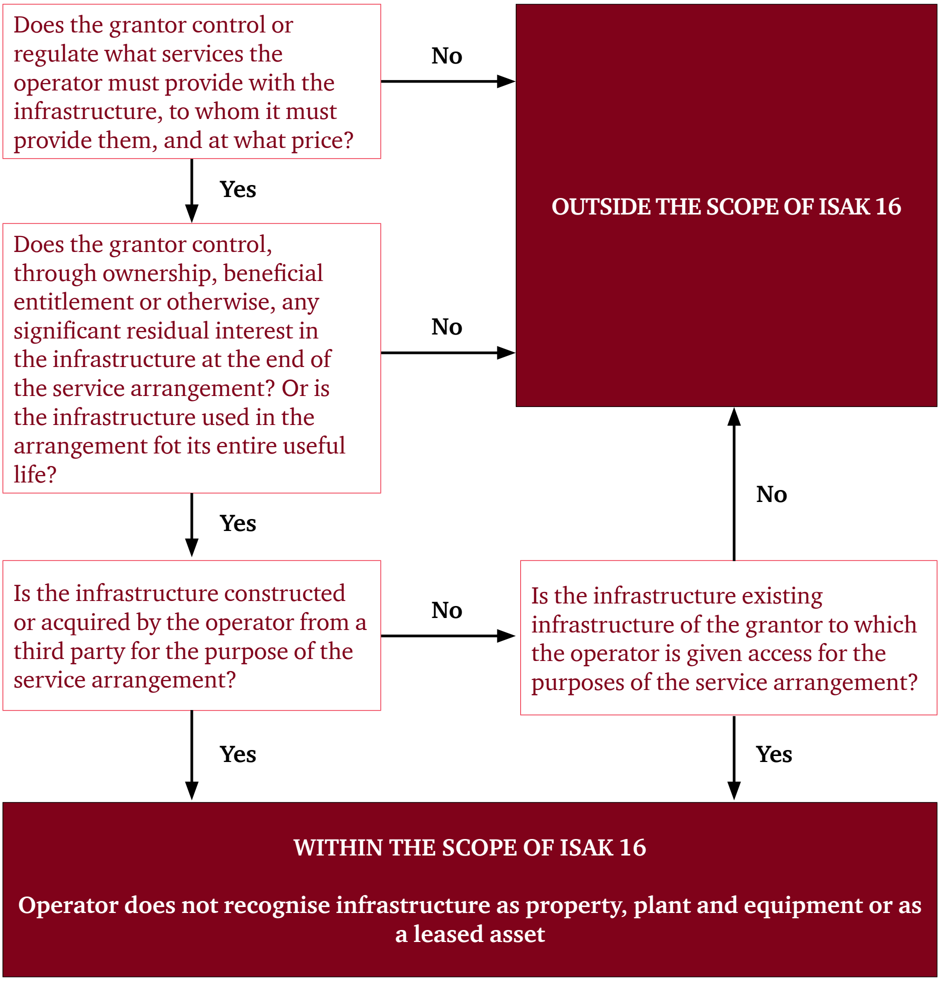
7.1.3 Application of accounting standards

The following diagrams summarise the method of determining when to apply ISAK 8 and ISAK 16.

ISAK 8 – Determining whether an arrangement contains a lease



ISAK 16 – Determining whether a service concession arrangement exists



PSAKs that apply to typical types of PPP arrangements

The table sets out the typical types of arrangements for private sector participation in the provision of public sector services and provides references to PSAKs that apply to those arrangements. The list of arrangement types is not exhaustive. The purpose of the table is to highlight the continuum of arrangements. It is not the PSAK's intention to convey the impression that bright lines exist between the accounting requirements for PPP arrangements.

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

7.1.4 Key accounting standards under PSAK, US Generally Accepted Accounting Principles ("US GAAP") and IFRS

The table below summarises the key standards and differences related to conventional power generation companies under PSAK, US GAAP and IFRS. For details of the key general accounting standards, please refer to our publication "IFRS and Indonesian GAAP (PSAK): Similarities and differences 2015".

Accounting for Conventional Power Generation			
A general comparison between Indonesian GAAP, US GAAP and IFRS			
Area	**IFRS**	**US GAAP**	**Indonesian GAAP**
Identification and classification of concession arrangements	PPP service concession arrangements that meet certain conditions must be analysed to determine whether the concession represents a financial asset or an intangible asset.	Consistent with IFRS in all significant respects	Consistent with IFRS in all significant respects
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

There are no specific accounting standards promulgated for power generation O&M businesses. Instead, generally accepted accounting standards usually apply.

7.3 Accounting for geothermal power generation

Key accounting standards for renewable energy projects are the same as those relevant for conventional power generation as discussed in Chapter 4.

However, the accounting treatment for geothermal exploration and evaluation (E&E) is similar to activities in the oil & gas industry and can be used as guidance in treating E&E costs.

Exploration, as defined in PSAK 64 Exploration and Evaluation of Mineral Resources (equivalent to IFRS 6) starts when the legal rights to explore have been obtained. 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 subsequent development costs:
a) Successful efforts; and
b) Full cost.

Debate continues within the industry on the conceptual merits of both methods although neither is wholly consistent with the PSAK framework. PSAK 64 provides an interim solution for E&E costs, pending the issuance of wider extractive industries accounting standards.

An entity should account for its E&E expenditure by developing an accounting policy that complies with the PSAK framework or in accordance with the exemption 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 that is closer to the principles of the IFRS framework.

Costs incurred after the probability of economic feasibility has been established are capitalised only 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 the PSAK and the IFRS, please refer to our publication “IFRS and Indonesian GAAP (PSAK): similarities and differences”.

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”.

7.4 IFRS 15 – A new model to recognise revenue

Effective 1 January 2018, all financial statements prepared under IFRS will have to apply the new IFRS 15, 'Revenue from Contracts with Customers' accounting standard to determine the timing and amount of revenue that can be recognised for the sale of goods and services. While the determination of revenue recognition pattern under the existing IAS 18, 'Revenue' standard mainly focuses on the timing of the transfer of risks and rewards of ownership of the goods being sold, IFRS 15 introduces a new revenue recognition model that emphasises the satisfaction of performance obligations identified in a contract with customers for a seller to recognise revenue. Entities will now have to apply a five-step approach 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 separate performance obligations
Step 5 : Recognise revenue when (or as) the performance obligation is satisfied

Entities will need to exercise judgement when considering the terms of the contract and all of the facts and circumstances, including implied contract terms. The introduction of a new revenue recognition model may change the timing and amount of the top-line revenue of many power companies.

Below, we highlight a number of potential scenarios that are likely to change the current revenue recognition practice for power companies following the adoption of IFRS 15. Our analysis has not been written to provide a comprehensive list of all potential cases, as there may be other areas of complexity identified in the different types of contact that power companies currently use. We may identify additional issues as more power companies begin to apply IFRS 15 and our views may evolve during that process.

Potential impact on power companies

Potential scenario	Potential impact
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 IFRS 16, 'Leases' (see below for further analysis of this standard), IFRS 15 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 IFRS 15 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 customer) and 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 considerations	• Contingent considerations are another common feature found in PPAs where payment for the electrical supply is adjusted for actual heat rate, performance bonus, step-up prices, etc. • IFRS 15 allows a power company to estimate the amount of variable consideration upfront and include them 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 revenue from contingent considerations 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 IFRS 15.

Potential scenario	Potential impact
Contract costs	• There is currently little guidance on how power companies should account for the costs spent to obtain a PPA. IFRS 15 allows power companies to capitalise certain costs to obtain a contract, which may include the commission fees payable to agents to obtain a PPA. • Once contract costs are capitalised, they should be amortised on a systematic basis over the contract period. Consequently, the new IFRS 15 treatment may change the pattern of cost recognition, and operating profit, over the contract period.
Contract modification	• Another potential area requiring judgment in the implementation of IFRS 15 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 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 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 IFRS 15, 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.

Transitional provisions

Application of IFRS 15 for IFRS reporters
IFRS 15 is effective for reporting periods beginning on or after 1 January 2018. Earlier adoption is permitted. Power companies may have to change their processes and information systems to capture the information they need.

7.5 IFRS 16 – A new era of lease accounting

In January 2016, the IASB issued IFRS 16, 'Leases' with an effective date of 1 January 2019. In contrast to the existing IAS 17 standard on leasing that requires a lessee to make a distinction between a finance lease (balance sheet) and an operating lease (off-balance sheet), the new IFRS 16 model will require lessees to capitalise nearly all leases on the balance sheet to reflect the right to use an asset for a period of time and the associated liability for payments to use the asset, except for certain short-term leases that are less than twelve months and leases of low-value assets below USD5,000.

IFRS 16 will therefore affect almost all commonly used financial ratios and performance metrics including debt-to-equity, current ratio, interest coverage, earnings before interest and taxes ("EBIT"), earnings before interest, taxes, depreciation and amortisation ("EBITDA"), return on capital employed and operating and financing cash flows. In fact, according to an IASB study published in January 2016, it is estimated that the top energy companies in the world are expected to add USD3 billion in lease liabilities and assets to their balance sheets as a result of the implementation of IFRS 16.

These changes may affect the loan covenants, credit ratings, borrowing costs, and could drive other changes to the business model of companies.

Why is IFRS 16 important to power companies?

Currently, there is no significant difference in the accounting treatment of an operating lease and a supply contract. The existing IFRIC 4, "Determining Whether an Arrangement Contains a Lease" provides guidance on the evaluation of whether a supply contract may contain an embedded lease element, with the result that many companies are simply focusing on identifying whether the arrangement actually results in a finance lease. This is because the accounting treatment of an operating lease and a supply contract is almost identical, as both arrangements are effectively off-balance sheet and the expenses are capitalised as incurred in profit or loss over a period of time.

Under IFRS 16, however, the treatment of the two arrangements will differ. With the removal of the off-balance sheet model under the new standard, the determination of whether an arrangement contains a lease becomes far more important. The new definition of a lease under IFRS 16 will be of particular interest to power companies when assessing long-term arrangements for the purchase of inputs and the sale of electrical outputs. Once it is 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?

IFRS 16 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 asset
An asset can be identified implicitly or explicitly in the contract. A contract may explicitly define a particular asset (e.g. a specific power plant that will have to be used in a specific location); or implicitly when the supplier can fulfill the contract only through the use of a particular asset (e.g. it is practically uneconomical to bring in another power plant from another location to fulfill the contract). A right to substitute an asset if it is not operating properly, or if there is a technical update required, does not prevent the contract from being dependent on an identified asset.

Right to control the use of an identified asset
The definition of a lease is now much more 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 from the use of an asset (the 'benefits' element), but 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 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, the contract would be classified as a lease under IFRIC 4. IFRS 16, however, requires not only that the customer obtains substantially all of the economic benefits from the use of the asset but also 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).

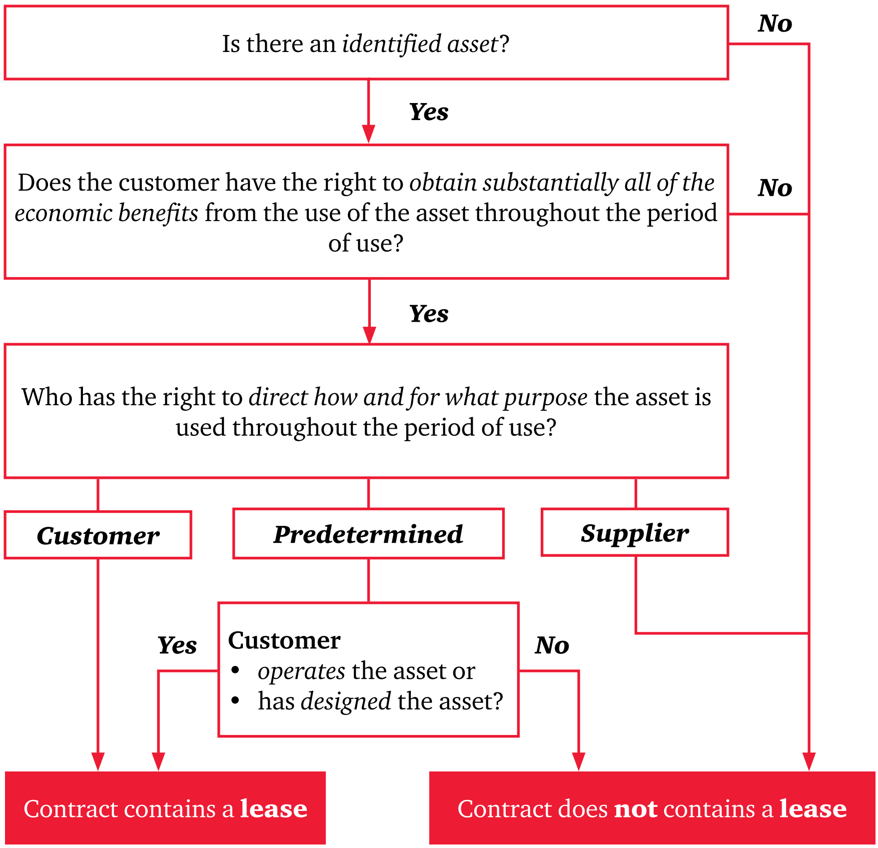
The right to control the use of an identified asset is the key distinctive factor, because in a lease, the customer has control over the right to use the identified asset, whereas, in a simple supply contract, the supplier retains control over the use of the particular asset.

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. IFRS 16 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;
d) the right to change how much of the output is produced.

The list is not exhaustive and none of the above criteria is independently exclusive, meaning there is no threshold to determine which criterion is more important than the other. The relevance of each of the decision-making rights depends on the underlying asset being considered. In a typical electrical power supply arrangement, for example, it is important to

address which party has the rights to determine:
a) How much power will be delivered and when;
b) When to turn the power plant on/off;
c) Which party has physical access to the power plant;
d) Whether the customer has the rights 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 to determine whether a contract contains a lease:



Illustrative applications

IFRS 16 includes three illustrative examples of how a contract to purchase electrical power from a solar farm can be assessed to determine whether a lease element is embedded in the contract. We have analysed all of the three examples from the standard and tailored them to illustrate the commonly found features 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 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 anytime.

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>

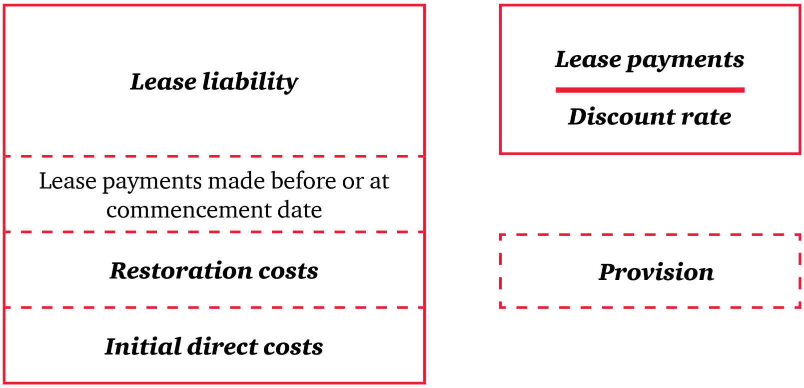
The contract contains a lease for the following reasons:
• There is an identified asset and it is uneconomical for the supplier to substitute the plant with another asset from a different location;
• The customer has the right to obtain substantially all of the economic benefits from the use of the power 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 use of the identified power plant over the 20-year period of use. The contract sets out the quantity and timing of power that the power plant will produce throughout the period of use, which cannot be changed in the absence of 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 in 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 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.
Customer's rights	**Supplier's rights**	**Conclusion**
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
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 during the lease term that are not yet paid. 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 spent to obtain the contract and contractually obligated restoration costs.

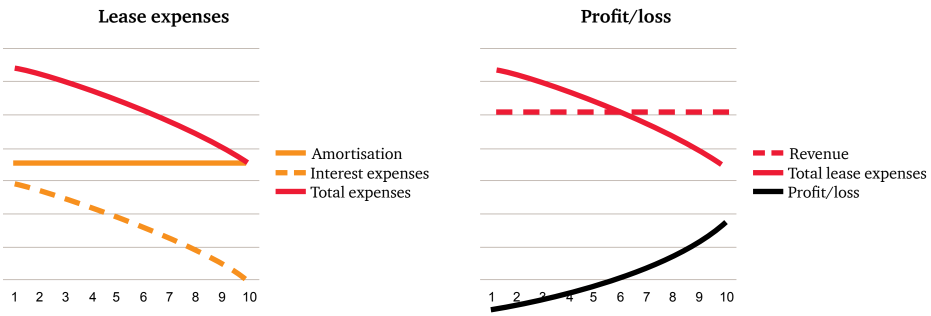
There is no change to the approach to determining the discount rate for the lease. The lessee uses as its discount rate the interest rate implicit in the lease. If this rate cannot be readily determined, the lessee should instead use its incremental borrowing rate.



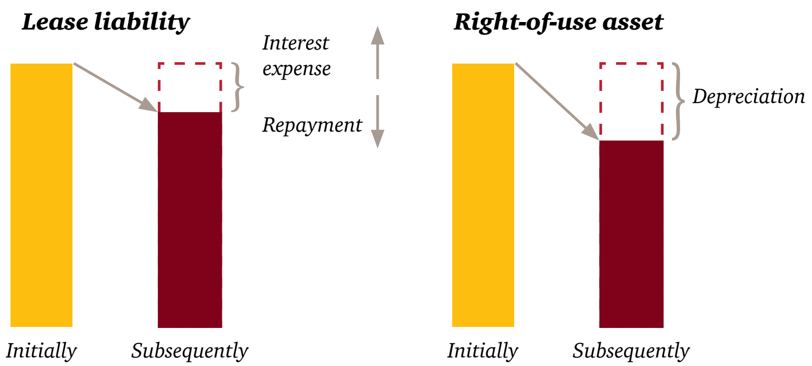
The effect of this approach is a substantial increase in the amount of capitalised financial liabilities and assets for entities that have entered into significant lease contracts that are currently classified as operating leases.

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 in IAS 16, "Property, Plant and Equipment", which will result in depreciation on a straight-line basis or another systematic basis that 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 applied to the lease liability results in a decreasing total lease expense throughout the lease term. This effect is sometimes referred to as *frontloading*.



The carrying amount 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 below the carrying amount of the lease liability.



Potential impact on the lessee's key performance indicators

Below, we summarise the potential effects of the new IFRS 16 requirement to capitalise substantially all leases on the balance sheet on a typical lessee's financial performance:

Indicator	Impact from IFRS 16
Debt-to-equity	This will increase because all lessees will now capitalise the lease liability of operating leases (which were recorded off-balance sheet under IAS 17).
EBIT	This will increase because typically the depreciation from the right-of-use of the asset added to this measure is lower than the removal of lease payments that were previously presented as operating expenses under IAS 17.
EBITDA	This will increase because of the removal of lease payments that were previously presented as operating expenses under IAS 17.

Indicator	Impact from IFRS 16
Operating cash flow	This will increase because operating lease payments that were previously presented as part of operating cash flow are now presented as part of financing cash flow; even though it is somewhat offset against higher cash outflows from the finance costs of the lease.
Financing cash flow	This will decrease because 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 related 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 IFRS 16 as it was under IAS 17. The lessor still has to classify leases as either finance or operating, depending on whether substantially all of the risk 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 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.

Transitional provisions

Application of IFRS 16 for IFRS reporters

IFRS 16 is effective for reporting periods beginning on or after 1 January 2019. Earlier application is permitted, but only in conjunction with IFRS 15 which is effective for the financial reporting period starting 1 January 2018. This means that an entity is not allowed to apply IFRS 16 before applying IFRS 15.

Entities are not required to reassess existing lease contracts but can elect to apply the guidance regarding the definition of a lease only to contracts entered into (or changed) on or after the date of initial application ("grandfathering"). If an entity chooses this expedient, it shall be applied to all of its contracts. Acknowledging the potentially significant impact of the new lease standard on a lessee's financial statements, IFRS 16 does not require full retrospective application, but instead allows a simplified approach. Full retrospective application is optional.

Application of IFRS 15 and 16 for PSAK reporters

As at the time of writing, the Indonesian Accounting Standards Board ("Indonesian ASB") has not formally adopted IFRS 15 and 16. However, given the Indonesian ASB's commitment to reach convergence with IFRS, and with the Indonesian economy becoming more integrated with the world by the day, we expect that the Indonesian ASB will soon introduce the principles of IFRS 15 and 16 into the PSAK literature.

Appendices

Photo source: PwC

List of 35 GW Power Development Programme Projects

IPP

NO	NAME OF PROJECT	PROVINCE	CAPACITY (MW)	PROCUREMENT METHOD	PROJECT STATUS
1	PLTU Jawa-1 (Exp. Cirebon)	West Java	1X1000	Direct Appointment	Financing Stage
2	PLTA Hasang (FTP2)	North Sumatra	40	Direct Appointment	Financing Stage
3	PLTA Malea	South Sulawesi	90	Direct Appointment	Financing Stage
4	PLTU Jeneponto-2 (Exp. Jeneponto)	South Sulawesi	2x112.5	Direct Appointment	Construction Stage
5	PLTB Samas	Yogyakarta	50	Direct Appointment	Financing Stage
6	PLTA Meurebo	Aceh	56	Direct Appointment	Procurement Stage
7	PLTA Merangin	Jambi	350	Direct Appointment	Procurement Stage
8	PLTU Sumsel-6 (Exp. Sp Belimbing)	South Sumatra	2x300	Direct Appointment	Procurement Stage
9	PLTA Karangkates & Kesamben	East Java	137	Direct Appointment	Procurement Stage
10	PLTU Jawa-5 (FTP2)	Banten	2x1000	Open Tender	Will be converted into PLN project
11	PLTU Kalbar-1	West Kalimantan	2x100	Open Tender	Financing Stage
12	PLTU Kendari 3	South East Sulawesi	2x50	Open Tender	Financing Stage
13	PLTU Sumsel 9	South Sumatra	2x600	Open Tender	Procurement Stage
14	PLTU Sumsel 10	South Sumatra	1x600	Open Tender	Procurement Stage
15	PLTU Sumbagsel-1MT	South Sumatra	2x150	Open Tender	Procurement Stage
16	PLTU Meulaboh 3&4	Aceh	2x200	Open Tender	Procurement Stage
17	PLTU Bengkulu	Bengkulu	2x100	Open Tender	Financing Stage
18	PLTU Sulbagut 1	Gorontalo, South Sulawesi	2x50	Open Tender	Procurement Stage
19	PLTU Sumsel-1 MT	South Sumatra	2x300	Open Tender	Financing Stage
20	PLTG Bangka Peaker	Bangka Belitung	100	Open Tender	Financing Stage
21	PLTU Jawa-7	Banten	2x1000	Open Tender	Financing Stage
22	PLTG/U Senipah Exp. (ST)	East Kalimantan	1x35	Direct Appointment	Procurement Stage
23	PLTU Kaltim 4 (Exp-2 Embalut)	East Kalimantan	2x100	Direct Appointment	Procurement Stage

NO	NAME OF PROJECT	PROVINCE	CAPACITY (MW)	PROCUREMENT METHOD	PROJECT STATUS
24	PLTU Jawa-4 (Exp. Tj Jati B)	Central Java	2x1000	Direct Appointment	Financing Stage
25	PLTU Sulbagut-3 (Exp. Molotabu)	Gorontalo, South Sulawesi	2x50	Direct Appointment	Procurement Stage
26	PLTA Wai Tina	Maluku	12	Direct Appointment	Procurement Stage
27	PLTA Sidikalang-1	North Sumatra	15	Direct Appointment	Financing Stage
28	PLTA Tabulahan	West Sulawesi	20	Direct Appointment	Procurement Stage
29	PLTA Masupu	West Sulawesi	36	Direct Appointment	Procurement Stage
30	PLTA Salu Uro	South Sulawesi	95	Direct Appointment	Procurement Stage
31	PLTU Sumsel-7 (Exp. Sumsel-5)	South Sulawesi	1x300	Direct Appointment	Procurement Stage
32	PLTU Jawa-8 (Exp. Cilacap)	Central Java	1x1000	Direct Appointment	Financing Stage
33	PLTA Kalaena-1	South Sulawesi	54	Direct Appointment	Procurement Stage
34	PLTA Paleleng	South Sulawesi	40	Direct Appointment	Procurement Stage
35	PLTA Poso 1	Central Sulawesi	120	Direct Appointment	Procurement Stage
36	PLTU Jawa-9 (Exp. Banten)	Banten	1x600	Direct Appointment	Procurement Stage
37	PLTA Air Putih	West Sumatra	21	Direct Appointment	Construction Stage
38	PLTU Muko Muko	Bengkulu	2x7	Open Tender	Procurement Stage
39	PLTU Jambi	Jambi	2x600	Open Tender	Procurement Stage
40	PLTMG Luwuk	Central Sulawesi	40	Open Tender	Procurement Stage
41	PLTGU Riau	Riau	250	Open Tender	Procurement Stage
42	PLTGU Jawa-1	West Java	2x800	Open Tender	Procurement Stage
43	PLTU Sinabang	Aceh	2x7	Open Tender	Procurement Stage
44	PLTG/MG Pontianak Peaker	West Kalimantan	100	Open Tender	Procurement Stage
45	PLTGU/MGU Sumut Belawan	North Sumatra	250	Open Tender	Procurement Stage
46	PLTGU/MGU Sulbagut 3	North Sulawesi	200	Open Tender	Procurement Stage
47	PLTGU/MGU Sulsel	South Sulawesi	150	Open Tender	Procurement Stage

NO	NAME OF PROJECT	PROVINCE	CAPACITY (MW)	PROCUREMENT METHOD	PROJECT STATUS
48	PLTGU/MGU Kalselteng	South/Central Kalimantan	200	Open Tender	Procurement Stage
49	PLTGU/MGU Peaker Jawa-Bali 1	West Java	400	Open Tender	Procurement Stage
50	PLTGU/MGU Peaker Jawa-Bali 2	East Java	500	Open Tender	Procurement Stage
51	PLTGU/MGU Peaker Jawa-Bali 3	Banten	500	Open Tender	Procurement Stage
52	PLTGU/MGU Peaker Jawa-Bali 4	West Java	450	Open Tender	Procurement Stage
53	PLTG/MG Jambi Peaker	Jambi	100	Open Tender	Procurement Stage
54	PLTGU Jawa-3	East Java	1x800	Open Tender	Financing Stage
55	PLTGU/MGU Sumbagut-1	North Sumatra	250	Open Tender	Procurement Stage
56	PLTGU/MGU Sumbagut-3	North Sumatra	250	Open Tender	Procurement Stage
57	PLTGU/MGU Sumbagut-4	Aceh	250	Open Tender	Procurement Stage
58	PLTU Sulut-3	North Sulawesi	2x50	Open Tender	Procurement Stage
59	PLTG/MG TB. Karimun	Riau	40	Open Tender	Procurement Stage
60	PLTG/MG Natuna-2	Riau	25	Open Tender	Procurement Stage
61	PLTMG Tanjung Pinang 2	Riau	30	Open Tender	Procurement Stage
62	PLTMG Dabo Singkep-1	Riau	16	Open Tender	Procurement Stage
63	PLTMG Bengkalis	Riau	18	Open Tender	Procurement Stage
64	PLTMG Selat Panjang-1	Riau	15	Open Tender	Procurement Stage
65	PLTMG Tanjung Batu	Riau	15	Open Tender	Procurement Stage
66	PLTG/MG Belitung	Bangka Belitung	30	Open Tender	Procurement Stage
67	PLTU Jawa-10	Central Java	1x660	Open Tender	Procurement Stage
68	PLTU Riau Kemitraan	Riau	2x600	Open Tender	Procurement Stage
69	PLTU Bangka-1	Bangka Belitung	2x100	Open Tender	Procurement Stage
70	PLTU Kalselteng-3	Central Kalimantan	2x100	Open Tender	Procurement Stage
71	PLTU Kalbar-2	West Kalimantan	2x200	Open Tender	Procurement Stage
72	PLTG/MG Natuna-3	Riau	25	Open Tender	Procurement Stage
73	PLTMG Dabo Singkep-2	Riau	16	Open Tender	Procurement Stage
74	PLTU Kaltim-3	East Kalimantan	2x200	Open Tender	Procurement Stage

PLN

NO	NAME OF PROJECT	PROVINCE	CAPACITY (MW)	PROCUREMENT METHOD	PROJECT STATUS
1	PLTU Lontar Ekspansi	Banten	1x315	Open Tender	Construction Stage
2	PLTG/MG Gorontalo Peaker	Gorontalo	100	Open Tender	Operation Stage
3	PLTA Upper Cisokan PS	West Java	1040	Open Tender	Procurement Stage
4	PLTMG Karimunjawa	Central Java	4	Open Tender	Procurement Stage
5	PLTGU Grati Peaker	East Java	450	Open Tender	Construction Stage
6	PLTGU Lombok Peaker	West Nusa Tenggara	150	Open Tender	Construction Stage
7	PLTA Asahan III	North Sumatra	2x87	Open Tender	Procurement Stage
8	PLTD Tersebar untuk daerah perbatasan dan pulau terluar	Various locations	68	Open Tender	Procurement Stage
9	PLTP Hululais	Bengkulu	55	Open Tender	Procurement Stage. In previous 35 GW plan, PLN only include 55 MW. The original size was 2 x 55 MW, however, initially the plan was to complete 55 MW in 2019 and the other 55 MW in 2020. In RUPTL 2016, all unit will be completed in 2018 - 2019.
10	PLTU Indramayu 4	West Java	1000	Open Tender	Procurement Stage
11	PLTGU Muara Karang Peaker	Jakarta	500	Open Tender	Procurement Stage
12	PLTGU Jawa 2 (Tj. Priok)	Jakarta	800	Open Tender	Procurement Stage
13	PLTGU Grati Add On Blok 2	East Java	150	Open Tender	Procurement Stage
14	PLTGU Muara Tawar Add On Unit 2,3,4	West Java	650	Open Tender	Procurement Stage
15	PLTU Kalselteng 2	Central Kalimantan	2x100	Open Tender	Procurement Stage
16	PLTG/PLTMG Lampung Peaker	Lampung	200	Open Tender	Procurement Stage
17	PLTP Tulehu	Maluku	20	Open Tender	Construction Stage
18	PLTU Lombok (FTP 2)	West Nusa Tenggara	2x50	Open Tender	Procurement Stage

NO	NAME OF PROJECT	PROVINCE	CAPACITY (MW)	PROCUREMENT METHOD	PROJECT STATUS
19	PLTU Lombok 2	West Nusa Tenggara	50	Open Tender	Construction Stage Planned capacity 2 x 50. The plan was to complete 50 MW in 2019 (part of 35 GW), and the other 50 MW will be completed in 2020.
20	PLTU Timor 1	East Nusa Tenggara	2x25	Open Tender	Procurement Stage. In RUPTL 2016, the capacity is upgraded to 2x50 MW
21	PLTP Mataloko	East Nusa Tenggara	20	Open Tender	Procurement Stage
22	PLTP Ulumbu 5	East Nusa Tenggara	5	Open Tender	Operation Stage
23	PLTG/PLTMG Riau Peaker	Riau	200	Open Tender	Procurement Stage
24	PLTU Sulsel Barru 2	South Sulawesi	1x100	Open Tender	Procurement Stage
25	PLTGU Makassar Peaker	South Sulawesi	450	Open Tender	Procurement Stage
26	PLTGU Sulsel Peaker	South Sulawesi	450	Open Tender	Procurement Stage
27	PLTU Sulsel 2	South Sulawesi	200	Open Tender	Procurement Stage. Planned capacity is 2 x 200. The plan is to complete 200 MW in 2019 (part of 35 GW), and the other 200 MW will be completed in 2020.
28	PLTU Palu 3	Central Sulawesi	2x50	Open Tender	Procurement Stage
29	PLTU Bau-bau	North Sulawesi	2x25	Open Tender	Construction Stage
30	PLTU Sulut 1	North Sulawesi	2x25	Open Tender	Procurement Stage
31	PLTG/PLTMG Mobile Power Plant Tersebar	Various locations	1565	Open Tender	Procurement Stage
32	PLTMG Tersebar	Various locations	665	Open Tender	Procurement Stage
33	PLTGU/MGU Tersebar	Various locations	450	Open Tender	Procurement Stage
34	PLTG/MG Tersebar	Various locations	250	Open Tender	Procurement Stage
35	PLTM Tersebar	Various locations	50	Open Tender	Procurement Stage

Source: PLN and PwC Analysis

Appendix B

Tax Incentives: Comparison for Conventional and Renewable Power Plants

		Conventional				Renewable			
Facility	Incentive	Income Tax	Import Duty	VAT	Article 22	Income Tax	Import Duty	VAT	Article 22
GR No. 18/2015	Investment allowance of 30% (over 6 years), accelerated depreciation and amortisation, reduced WHT on dividends paid to non-residents.	–	–	–	–	Potentially yes	–	–	–
MoF Regulation No.177/2007	Import duty exemption on import of goods used in "geothermal business activities" (requires a working area, survey licence or geothermal mining business licence). Goods and materials must: a) Not be produced in Indonesia; b) Be produced in Indonesia but not meeting the required specifications; or c) Be produced in Indonesia but in insufficient quantity.	–	–	–	–	–	Yes for geothermal investments	–	–
MoF Regulation No.66/2015	Import Duty exemption for import 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	–	–
MoF Regulation No.176/2009 (as amended by 76/2012 and 188/2015)	Import Duty exemption 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 exemption for importation (which the associated import duty is also exempt).	–	–	–	–	–	–	Geothermal only and only in exploration stage	–
GR No. 12/2001 (as amended by GR No.81/2015 and as implemented by MoF Regulation No.268/2015)	VAT exemption on import 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 can qualify).	–
MoF Regulation No. 21/2010	Art. 22 exemption for imports by IPPs involved in renewable energy.	–	–	–	–	–	–	–	Yes

Appendix C

Commercial & Taxation Issues by Stage of Investment

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

Stage of Investment	Issues Common to Conventional Power and Renewable Energy	Renewable Energy Specific Issues 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 • 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% • Treatment of spares or non-capital goods (materials)	• Renewable Energy (RE) incentives
Operation	• Input VAT costs • Regional taxes & levies • ISAK 16 accounting • ISAK 16 vs. conventional accounting (for tax) • VAT registration & compliance • O&M Fees – transfer pricing if paid to affiliate • Forestry License fees • Profit repatriation • 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 • Forestry License fees For hydro also: • Regional taxes and water levies
Overhaul Stage	• Capitalisation of expenditure & amortisation • Deductibility of repairs/ improvements	
Handover, of Facility Stage	• Taxes on divestment • Manpower costs – change of control provisions • Environmental provisions for site rehabilitation • Implications for any foundations established for CSR/Pension purposes	

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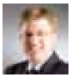

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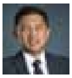

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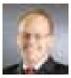

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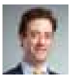

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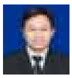

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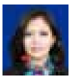

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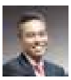

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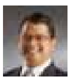

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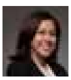

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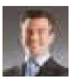

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DEDICATION

This report is dedicated to the memory of Anthony Joseph Anderson, 1971-2016, much loved and respected Partner at PwC Indonesia who sadly passed away prior to the completion of this guide.