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Supplying and Financing Coal-Fired Power Plants in the 35 GW Programme

March 2016

ASOSIASI PERTAMBANGAN
BATUBARA INDONESIA
INDONESIAN **COAL**
MINING ASSOCIATION

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Foreword

As Chairman of the Indonesian Coal Mining Association (*Asosiasi Pertambangan Batubara Indonesia*, "APBI"), I have commissioned PT PricewaterhouseCoopers Indonesia Advisory ("PwC") to produce this report on Supplying and Financing the 35 GW programme.

Over the past few years, the coal industry in Indonesia has faced serious economic challenges. With the 59% fall in global and local coal price since 2012, profitability has fallen to record lows and production cuts are widespread. Investment cuts have swiftly followed and exploration for new reserves has essentially stopped.

The power industry, on the other hand, is booming. President Joko Widodo has instructed the relevant Government agencies to develop an additional 35 GW of new power capacity. The programme requires the development of power plants across Indonesia in order to increase the electrification ratio from 87.5% in 2015 to 97.2% by 2019, or the end of his first presidential term.

The 35GW programme represents an opportunity to expand the supply of power across Indonesia and at the same time revive the domestic coal industry.

This report indicates that there may not be enough coal reserves at the current market price to reliably supply the 20 GW of new coal-fired power plants included in the 35 GW programme over their full lifetimes.

The report has several main findings:

1. The Government has made significant progress in accelerating the 35 GW programme but must retain focus on key acceleration measures to promote success.
2. Updates to coal reserve data have lagged behind the fall in the coal price, and reserves may be 29% lower than the last figures reported by coal companies, given the decrease in coal price. The implied reserves may not be sufficient to supply the 20 GW of new power capacity past 2036.
3. A strategy is needed to inject more capital into the power sector, and create active secondary markets for Indonesian infrastructure in which pension and insurance funds can invest.

The report outlines key ideas for policies that could be put in place to address some of the issues. In particular, long-term cost-based pricing for domestic coal represents an 'insurance policy', with a reasonable premium, that would stimulate investment, incentivize exploration, and secure reserves for a generation of power projects.

Coal remains the most cost-effective fuel source for power generation in Indonesia and plays to the country's natural resource abundance. Let us make sure that we are allocating our resources effectively, in a secure, long-term manner that allows the power and mining industries to invest for the future with certainty.

01

Glossary

ADB	Air Dried Basis
APBI	*Asosiasi Pertambangan Batubara Indonesia* (Indonesian Coal Mining Association)
arb	As Received Basis
ASEAN	Association of South East Asian Nations
baht	Thailand Baht
bcm	Bank cubic metre
bn	Billion
Capex	Capital expenditure
CCoW	Coal Contract of Works
CFPP	Coal-Fired Power Plants
CIF	Cost, Insurance and Freight
CIL	Coal India Limited
CMM	Coal Mine Mouth
COD	Commercial Operations Date
COP21	21st session of the Conference of the Parties (2015 Paris Climate Conference)
CoW	Contract of Work
CV	Calorific Value
D/EBITDA	Debt to EBITDA Ratio
D/E	Debt to Equity Ratio
DGoMC	Directorate General of Minerals and Coal
DLPK	Financial Institution Pension Funds
DMO	Domestic Market Obligation
DPPK	Employer-Sponsored Pension Funds
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
FOB	Free on Board
FSA	Fuel Supply Agreement
FTP	Fast Track Programme
GAR	Gross Calorific Value

Glossary (cont’d)

GC	Newcaslte Global Coal Index
GCI	Global Competitiveness Index
GDP	Gross Domestic Product
GW	Gigawatt
HBA	*Harga Batubara Acuan* (Indonesian Coal Price Reference)
HPB	*Harga Patokan Batubara* (Coal Benchmark Price)
ICI	Indonesia Coal Index
IEA	International Energy Agency
IPP	Independent Power Producer
IPR	*Izin Pertambangan Rakyat* (People's Mining License)
IUP	*Izin Usaha Pertambangan* (Mining Business License)
IUPK	*Izin Usaha Pertambangan Khusus* (Special Mining Business License)
IUPTL	*Izin Usaha Penyediaan Tenaga Listrik* (Electricity Business License for Public Use)
JORC	Joint Ore Reserves Committee
kcal	Kilocalorie
kg	Kilogram
km	Kilometre
KP	*Kuasa Pertambangan* (Coal Concessions)
kVa	Kilovolt-amps
kWh	Kilowatt Hour
LCoE	Levelized Cost of Electricity
MoEMR	Ministry of Energy and Mineral Resources
Mt	Million Tonnes
mVa	Megavolt-amps
MW	Megawatt

Glossary (cont'd)

MWh	Megawatt-hours
NAV	Net Asset Value
NEX	Newcastle Export Index
Opex	Operational Expenditure
PerMen	*Peraturan Menteri* (Ministerial Regulation)
PerPres	*Peraturan Presiden* (Presidential Regulation)
PAT	Profit After Tax
PLN	PT. Perusahaan Listrik Negara (State Electricity Company)
PMN	*Penyertaan Modal Negara* (Government Equity Injection)
PNBP	*Penerimaan Negara Bukan Pajak* (State's non-tax revenue)
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
RPJMN	*Rencana Pembangunan Jangka Menengah Nasional* (National Medium-Term Development Plan)
RUKN	*Rencana Umum Ketenagalistrikan Nasional* (General Plan of Electricity)
RUPTL	*Rencana Usaha Penyediaan Tenaga Listrik* (Electrical Power Supply Business Plan)
Rp	Indonesian Rupiah
SAIFI	System Average Interruption Frequency Index
SR	Stripping Ratio
T&D	Transmission and Distribution
TM	Total Moisture
TWh	Terawatt-hours
VA	Volt-amps
$	United States of America Dollar

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Important Notice

The report has been prepared by PT PricewaterhouseCoopers Indonesia Advisory for the Indonesian Coal Mining Association ("APBI") under the terms of our Engagement Letter dated 18 January 2016.

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Executive Summary

"Coal plays a vital role in meeting global energy needs and is critical to infrastructure development."

World Coal Association

Introduction

PwC and APBI jointly developed this white paper to examine ways to secure the supply of coal for the next generation of coal-fired power plants ("CFPP") under the 35 GW programme.

Our findings are based on:

- A confidential survey of mining companies
- Interviews with coal miners and Independent Power Producers ("IPP")
- Interviews with independent geologists
- Analysis of publicly available data on miners

These findings suggest a need for further research into several areas to optimize future policy. As such, they should be considered preliminary and subject to uncertainty.

Coal reserves at the current market price may be insufficient to guarantee supply to existing plants and 20 GW of new CFPP coming online before 2019

Publicly-listed companies data and our survey suggest proven reserves are currently only around 8.3 billion tonnes. This could last until only 2036 at projected rates of production, less than the operational lives of planned power plants.

Indonesia could consider a cost-based pricing mechanism (see page 10) for coal for domestic power generation

The Government **has a number of pricing options** open to it to bring about a more sustainable mining industry (see page 10). Extending a cost-based pricing system such as that for Coal Mine Mouth ("CMM") power plants to other CFPPs is one attractive option: this may help provide certainty of returns, in turn shoring up miners' balances sheets, returns and restoring investment. Cost-based pricing will increase the coal price paid relative to the current reference price, but could save PT. Perusahaan Listrik Negara ("PLN") costs if the reference price rises, or a shortage of coal supply leads to coal import and/or increased reliance on natural gas.

Executive summary

Coal is critical to Indonesia's development but the sector is suffering

Mining plays a significant role in the Indonesian economy. The mining industry accounts in 2014, directly and indirectly, for around 14% of Indonesia's GDP and $2.63 billion in non-tax revenue. Coal is the second-largest mining sector, and fuelled just over half of all power generated in 2015.

Yet, in recent years the industry has suffered from stagnant demand and over-supply. The Indonesian reference price, which tracks domestic and international spot prices, has fallen since the 2011 high; from $127/tonne in 2011 to $50.9/tonne in February 2016.

Despite offsetting falls in operational costs due to falling oil prices and other factors, Earnings Before Interest, Tax, Depreciation and Amortization ("EBITDA") has plunged with the coal price. Capital expenditure has fallen 79% since 2012 to end-2015, and many smaller miners have been put out of business. Leverage has risen significantly.

The supply of coal for the 35 GW programme is far from certain.

The government needs to secure long-term supply for 20 GW of new coal-fired power plants in the next 12 months if it is to realistically reach their Commercial Operations Date ("COD") before end-2019.

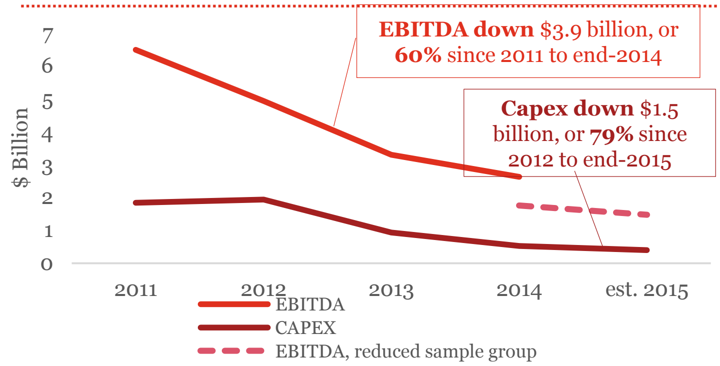
The majority of power and vast majority of mining investment require private sector capital, which is led by returns.

Economically mineable (or 'proven') reserves are a function of the price of coal. Although they do not directly change with the spot price, and allowance is generally made for price fluctuations in mine planning, in the long-run reserves move in line with the price of coal. Currently, stripping ratios are falling to reduce operational costs, but this may not be sustainable if coal is to serve as the primary fuel for Indonesia power generation; it simply increases the price needed in future to access the resources that were once reserves and may thus reduce total reserves now.

We used corporate data on coal reserves – combined with a confidential survey of APBI members to assess likely total proven reserves today.

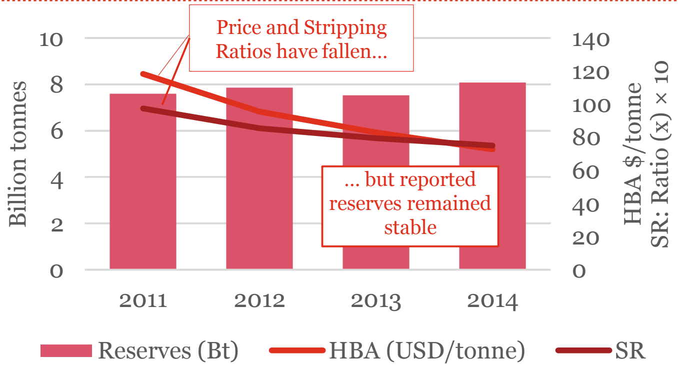
Reported reserves have remained stable even while coal prices (HBA; see page 48) and Stripping Ratios have fallen in recent years (see Figure below). But, our survey suggests mineable reserves would be 29% lower than reported 2012 figures if the current market price were used as the basis for long-term mine planning. This suggests reserves of 8.3 billion tonnes. With annual production projected by government (and extrapolated by us) to average around 350-400 million tonnes in future, **these reserves would run out in 2036.** This is less than 20 years into the lifecycle of the new power plants (typically 25-30 years from COD).

Capital Expenditure and EBITDA from Listed Mining Companies



Source: Bloomberg

Coal Reference Price (HBA), Stripping Ratio (11 Companies), Reported Reserves (15 companies)



Source: MoEMR, Company Annual Reports

Executive Summary

Policy options for securing reserves; cost-based pricing presents an attractive option

The Government has several options relating to the pricing of coal to address this potential issue, outlined in the table below.

Looking at the key costs and benefits of the options, it appears that cost-based pricing (the extension of something similar to current CMM cost-plus regulation to all power plants who wish to use it) poses an attractive 'insurance premium' of around 1.2%-3.2% of the power tariff to stimulate investment in IPPs[1] and mining exploration. The scope of cost-based pricing is uncertain (depending on how many power plants use it, and for how long), but would be partially offset by increased royalty revenue (see page 37). By providing a clear, long-term return it could encourage maintenance of reported reserves and stimulate new investment in exploration activities.

Restoration of miners' balance sheets, combined with solid incentives (sufficient Project rates of return and fair risk allocation in Power Purchase Agreements ("PPA")) could stimulate their investment in power plants, too. Currently, mining firms have limited equity or debt capacity to participate in the 35 GW programme.

Protecting the public sector purse

Currently, the cost data needed to estimate a detailed pricing mechanism is unavailable. It should not be assumed that current CMM costs are appropriate.

Regional differentiation is key to assessing the appropriate price range.

Safeguards are needed to protect taxpayer interests including: incentives to innovate and reduce operational costs; competitive bid pressure between coal suppliers; and commitment by the coal mining industry to honour long-term contracts even if spot markets boom again.

Accelerating infrastructure more broadly

The Government may also wish to consider additional steps to build on the progress to date in accelerating the 35 GW programme, including:

- Ensuring PLN makes full use of land acquisition powers granted under Presidential Regulation ("PerPres") 4/2016. It should be considered whether land for transmission beyond the interconnection point could become Government responsibility.
- Injecting the promised equity under PerPres 4/2016 for PLN, carefully targeting it at bottlenecks, such as transmission.
- Signaling its intent to extend reputable coal miners' licenses that expire during the term of Coal Supply Agreements.
- Further standardizing PLN bidding documents for IPP procurement.
- Devising a strategy for channeling pension/mutual funds to Indonesian infrastructure projects.

Coal Pricing Policy Options	Benefits	Costs/Risks
Do nothing	• No short-term cash costs • Avoids need for new regulation	• Risk of coal market disruption if Indonesian production falls • Risk of large cash costs as gas or imported coal becomes needed (likely extra billion(s) of dollars yearly after 2036; see page 37)
Encourage higher coal prices in IPP contracts	• Permitted already; avoids need for new regulation • Maintains some market signal	• Not transparent; prone to special treatment • Ad hoc treatment may not secure reserves and does not incentivize sector-wide investment
'Cost-based pricing' (long-term pricing based on costs)	• Encourages investment in mines and IPPs • Stabilizes reserves and secures supply • Upside to PLN on future HBA rises	• Likely cost of at least $400 million for PLN (see page 36) • Decoupling from international market signals
Restructure 35 GW programme; so more CMM pricing	• Optimizes coal supply/demand proximity; increases CMM capacity	• Similar costs to cost-based pricing, plus additional transmission costs (less shipping costs) • Massive disruption to planning and procurement • Transmission projects may not be feasible

[1] $38.3 billion of private investment is needed for the 35 GW programme. The 'insurance premium' is around 0.5%-1.5% of total capital expenditure required for the power programme ($73 billion).

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04

Overview of Coal Mining and Power Sector Related to 35 GW Programme

Contribution to Indonesian Economy

Mining has made a significant contribution to Indonesia's economic growth

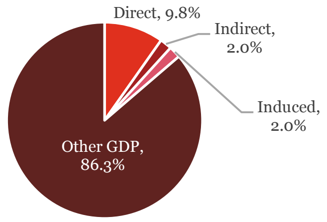
There is no doubt that the mining sector has been one of the key sectors supporting Indonesia's economic growth for a number of years. In 2014, the mining industry was the fourth-largest contributor to GDP, accounting for approximately 9.8% of Indonesian Gross Domestic Product ("GDP"), 13% of export revenue and 8.3% of total non-tax revenue

The industry represents an even larger share of the regional economies of many provinces, including Papua, Central Sulawesi, Bangka-Belitung, West Nusa Tenggara and East Kalimantan. This has been true even during the ups and downs in commodity prices during the past five years: from the mining boom of 2007, through the global economic downturn of 2008 - 2009, moderate recovery in 2010 - 2011, and a return to downward pressures from 2012 to the present.

The sector makes a significant contribution to Indonesian GDP, exports, Government revenues, employment and, perhaps most importantly, the economic development of the remote regions where mining operations are located.

Mining also makes a significant contribution to other economic sectors. We calculate that the value-added multiplier impact of the mining and quarrying industry is 1.2 for the supply chain and 1.4 including the spending of worker's wages [2]. This implies the total economic contribution of the sector is around 14% of GDP.

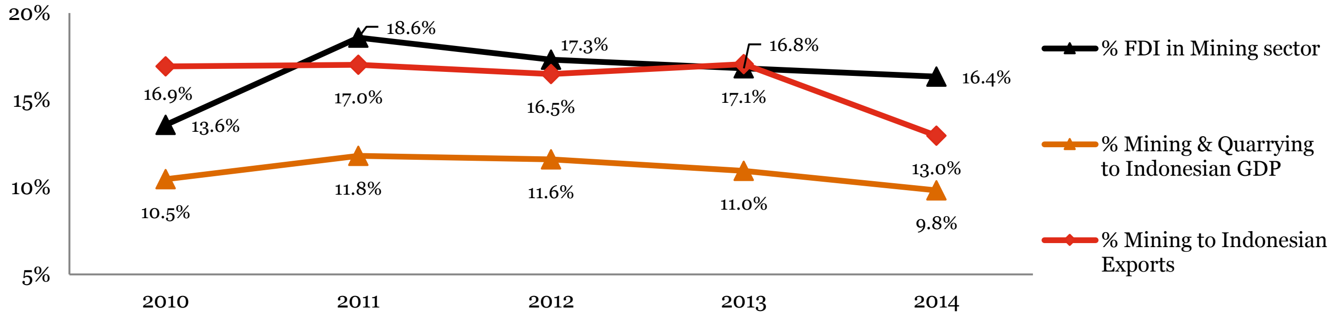
Figure 1: Mining Contribution to Indonesian GDP, including Multiplier Effects



Within the mining and quarrying sector, coal mining is the second largest contributor, at 2.4% of GDP. The realization of the State's non-tax revenue (*Penerimaan Negara Bukan Pajak*, "PNBP") from coal sales reached Rp 26.3 trillion by 2014, or 81% of the total PNBP revenue from the mining sector. In 2015, the Government targeted PNBP revenue from the mining sector at Rp 52.2 trillion, however as of the end of 2015, it had merely reached Rp 29.6 trillion or only 57 % of the target, and coal sales had reached 80% of the total PNBP from the mining sector [3].

Indonesia is one of the world's leading thermal coal producers and since 2012 has been the world's top exporter of thermal coal, exporting 359 million tonnes of 435 million tonnes domestically produced in 2014. This generated $22.3 billion of export earnings.

Figure 2: Contribution of Mining Sector to Indonesian Economy



[2] PwC analysis based on macroeconomic model of Indonesia (Source: World Input Output Database 2011)

[3] Statement of MoEMR's Director of Minerals and Coal in Jakarta on 10 February 2016

Overview of Global Coal Market

World's coal reserves

Coal is considered an abundant yet finite fossil fuel. Of all energy sources, coal is generally the least expensive given its energy content. It is available in a wide variety of globally-distributed mines.

More than 80% of the world's total proven coal reserves are located in ten countries (see Box 1 on page 16 for an explanation of resources and reserves). There was an estimated 892 billion tonnes of proven coal reserves worldwide in 2014 [4]. Current coal reserves should last for around 110 years.

According to the most recent data, the five biggest reserves are found in the USA, Russia, China, Australia and India. Indonesia currently ranks tenth (3.1% of the global total).

World coal production declined by 0.7% in 2014 from 2013. Based on IEA data, the top five coal producers in 2014 were (Mt): China 3,650 (46.1%), United States 916 (11.6%), India 668 (8.4%), Australia 491 (6.2%), and Indonesia 471 (5.9%)[5].

Global coal consumption

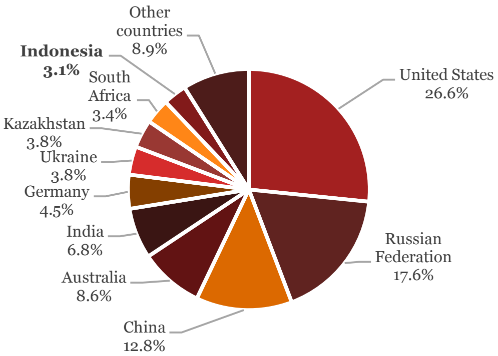
Global coal consumption is growing and expected to continue as developing countries expand their energy needs. Coal plays a vital role in power generation: it fueled 41% of the world's electricity needs as at 2013.

Looking at the historical trend, coal consumption increased by 71.2% from 4,600 Mt in 2000 to an estimated 7,876 Mt in 2013. Since then demand has remained broadly flat: it decreased by 0.4% in 2014, after growing by 1.8% in 2013.

Global demand varies significantly according to geography. China has historically been the largest consumer and importer [6]. India is expected to become the second-largest coal consumer in the world, and the largest importer.

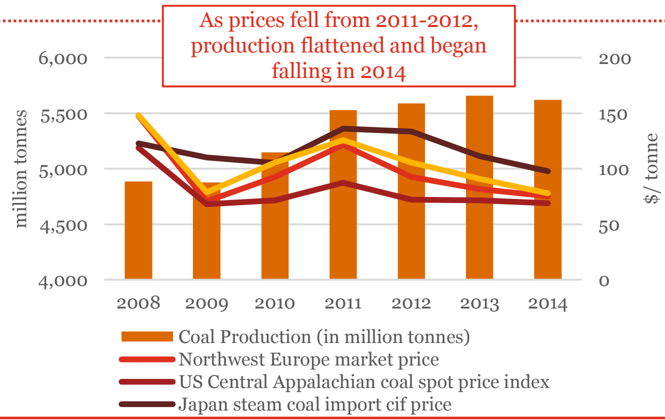
According to the IEA, global coal demand growth has been slowing in recent years, and the trend will be continuing[7] in reflection of economic rebalancing in China and environmental and renewable energy policies worldwide including the recent climate agreement (COP21) in Paris.

Figure 3: World's Proven Coal Reserves by 2014



Source: BP Statistical Review of World Energy June 2015

Figure 4: World's Coal Production and Price



Source: BP Statistical Review of World Energy June 2015

[4] Source: BP Statistical Review of World Energy June 2015

[5] Source: IEA Statistics Coal Information 2015. This differs from MoEMR information on other pages due to differing data and methodology.

[6] Source: IEA Keyworld Statistic 2013

[7] Source: : http://www.iea.org/newsroomandevents/pressreleases/2014/december/global-coal-demand-to-reach-9-billion-tonnes-per-year-by-2019.html

Overview of Indonesia's Coal Market

Indonesia's coal reserves

According to the Ministry of Energy and Mineral Resources ("MoEMR") data, there were an estimated 32.3 billion tonnes of proven coal reserves and 124.8 billion tonnes of total resources in Indonesia at the beginning of 2014 [8].

As at 2013, the largest coal reserves in Indonesia could be found in South Sumatra, East Kalimantan and South Kalimantan.

The majority (64%) of Indonesia's coal reserves are categorized as medium rank, followed by low rank (28%).

Coal production

Indonesian production decreased by 14% to 392 million tonnes in 2015. This is the first time since 2012 that Indonesia's production fell below 400 million tonnes.

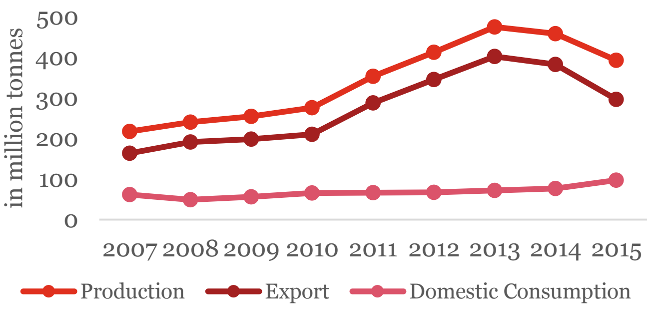
From total production, 296 million tonnes were exported in 2015, a decrease of 23%. The nation's coal exports dropped significantly as coal companies continued to suffer from low prices in addition to becoming increasingly dependent on the domestic market. More detailed analysis of the state of the industry is provided on pages 27-28.

Figure 5: Indonesian Coal Reserves by Rank, 2014

Rank	Reserves (million tonnes) Total	%	Calorific Value (GAR)
Low Rank	9,193	28%	< 4,700 kcal/kg
Medium Rank	20,693	64%	4,700 - 5,700 kcal/kg
High Rank	1,554	5%	5,700 – 6,700 kcal/kg
Very High Rank	945	3%	> 6,700 kcal/kg
TOTAL	**32,385**	**100%**	

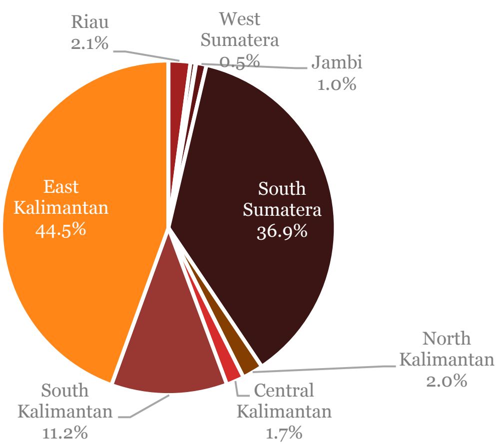
Source: MoEMR (Discussion of Coal Provision for Power Plant Needs), 2015.
Note: 0.3% discrepancy with total above or from 2014 data

Figure 7: Production, Domestic Consumption, Export



Source: MoEMR Data, 2015

Figure 6: Indonesian Coal Reserves by Province, 2014



Source: Handbook of Energy & Economics Statistics of Indonesia, 2015

Figure 8: Coal Price

Source: GEM Commodities, World Bank, 2015

[8] Source: MoEMR 'Handbook of Energy & Economics Statistics of Indonesia 2015'

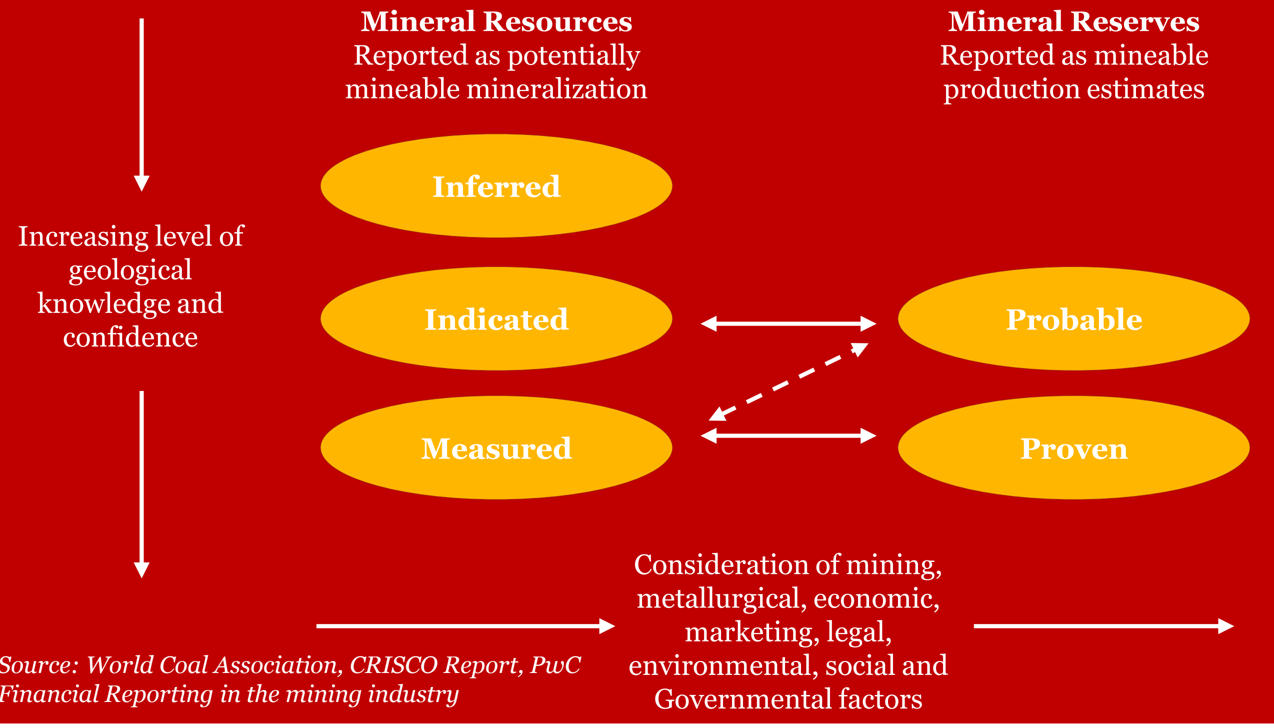
Box 1: What is the difference between Resources and Reserves?

What Are Resources?
The amount of coal that may be present in a deposit or coalfield. This does not take into account the feasibility of mining the coal economically. Not all resources may be recoverable using current technology. Resources are classified into:

- Inferred; estimated with a low degree of confidence based on geological evidence
- Indicated; estimated with a reasonable degree of confidence based on sampling
- Measured; estimated with a high degree of confidence (by a 'competent person') following further sampling

What Are Reserves?
Reserves can be defined in terms of proven (or measured) reserves and probable (or indicated) reserves. Probable reserves have been estimated with a lower degree of confidence than proven reserves.

What Are Proven Reserves?
Reserves that are not only considered to be recoverable but can also be recovered economically. This means they take into account what current mining technology can achieve and the economics of recovery. Proven reserves will therefore change according to the price of coal; if the price of coal is low, proven reserves will generally decrease.



Source: World Coal Association, CRISCO Report, PwC Financial Reporting in the mining industry

Importance of Power to the Indonesian Economy

Indonesia's infrastructure development lags behind economic growth, and may hinder it

Indonesia currently has a total population of approximately 254 million, including an emerging middle class of some 74 million[9]. At the same time, Indonesia is currently experiencing rapid urbanization and more broadly, fast economic and industrial growth. This stress on the power grid manifests itself in blackouts and brownouts.

This has led to greater electricity consumption. In 2015, Indonesia generated 219 TWh to meet this need, up from 147 TWh in 2010.

Growth in energy consumption is expected by PLN to be around 7-8% between 2015 and 2024[10].

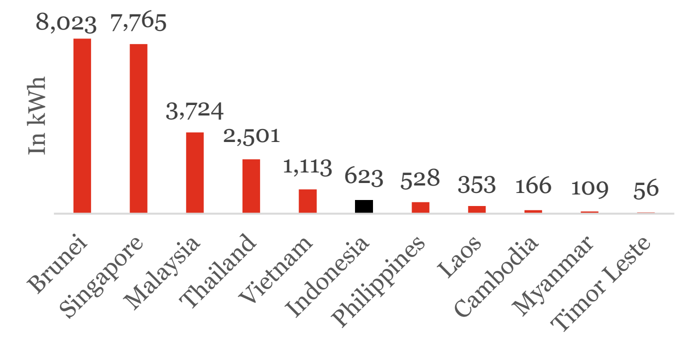
Based on PLN's System Average Interruption Frequency Index ("SAIFI"), the average Indonesian consumer experiences electricity interruptions five times a year, which is more often than several regional competitors (see Figure 10).

Power is considered a main bottleneck to growth. Based on the World Economic Forum's Global Competitiveness Index ("GCI") report, Indonesia is ranked 84th out of 144 countries in terms of its infrastructure development in electricity supply. Indonesia currently ranks behind neighbouring countries such as Singapore and Malaysia.

And yet power demand is likely to continue rising further. Within the Association of South East Asian Nations ("ASEAN"), Indonesia is ranked sixth in terms of electricity consumption per capita, at 623 kWh/capita in 2014, still lower than Brunei, Singapore, Malaysia, Thailand, and Vietnam[11] (see Figure 9). Indonesia is likely to experience continued growth in demand for power: the electrification ratio in 2015 was 87.5%[12].

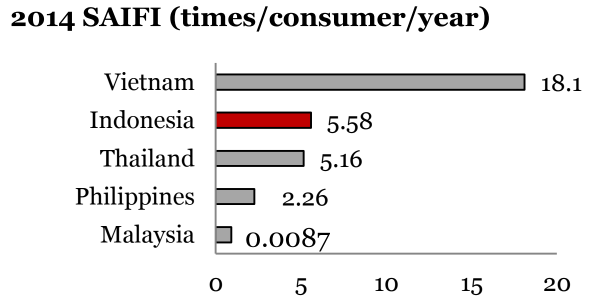
Continued power supply will therefore be crucial to meet continued demand, creating a reliable supply for business and industry, and meeting social targets to electrify communities across Indonesia.

Figure 9: Electricity Consumption per Capita in ASEAN, 2014



Source: Indexmundi

Figure 10: System Average Interruption Frequency Index, 2014



Source: PwC Analysis

[9] Source:https://www.bcgperspectives.com/content/articles/center_consumer_customer_insight_consumer_products_indonesias_rising_middle_class_affluent_consumers/#chapter1

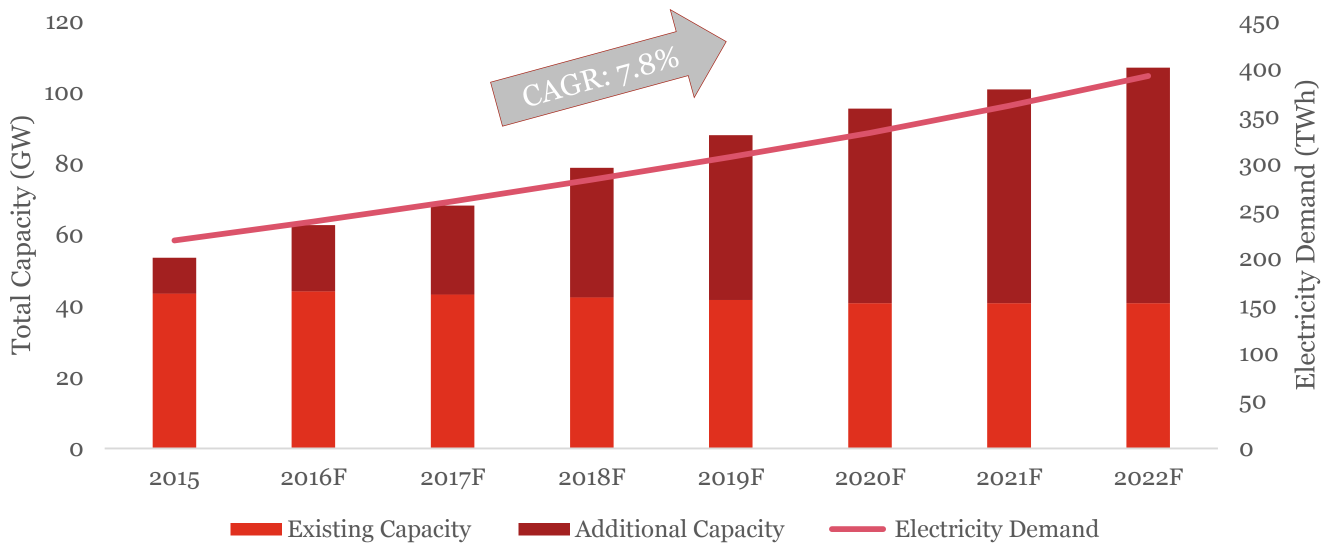
[10] Source: PLN

[11] Source: http://www.indexmundi.com/g/r.aspx?v=81000

[12] Source: Ministry of Finance, http://www.kemenkeu.go.id/en/Berita/government-pursues-electrification-ratio-972-percent-2019

Overview of Indonesia Power Supply and Demand

Figure 11: PLN Projected Electricity Capacity and Consumption, 2015-2022



Source: PLN RUPTL 2015-2024
Note: PLN's methodology calculates capacity to meet forecast demand, so by definition there is no projected shortfall in supply

The current administration is targeting the development of 35 GW of additional power capacity

In October 2014, President Joko Widodo took office, and set new targets to electrify the nation. First and foremost to support projected growth for power demand of 7.8% per year until 2022, the Government of Indonesia announced a target to develop 35 GW of new capacity.

The development of the 35 GW programme will be done alongside the remaining ongoing projects from the Fast Track Programme ("FTP") I and II with a total capacity of 7 GW. These combined programs will, therefore, have a total target capacity of 42 GW for Indonesia, targeted to be operational by the end of 2019.

Of this 42 GW, 28 GW is expected to be provided by IPPs under long-term PPAs and 14 GW directly contracted by PLN.

The total capital expenditure required for the power programme is $73 billion[13], comprising:

- Generation capacity: $53.7 billion.
- Transmission and distribution capacity: $10.9 billion and $8.4 billion, respectively.

Figure 12: Planned Power Projects 2015-19

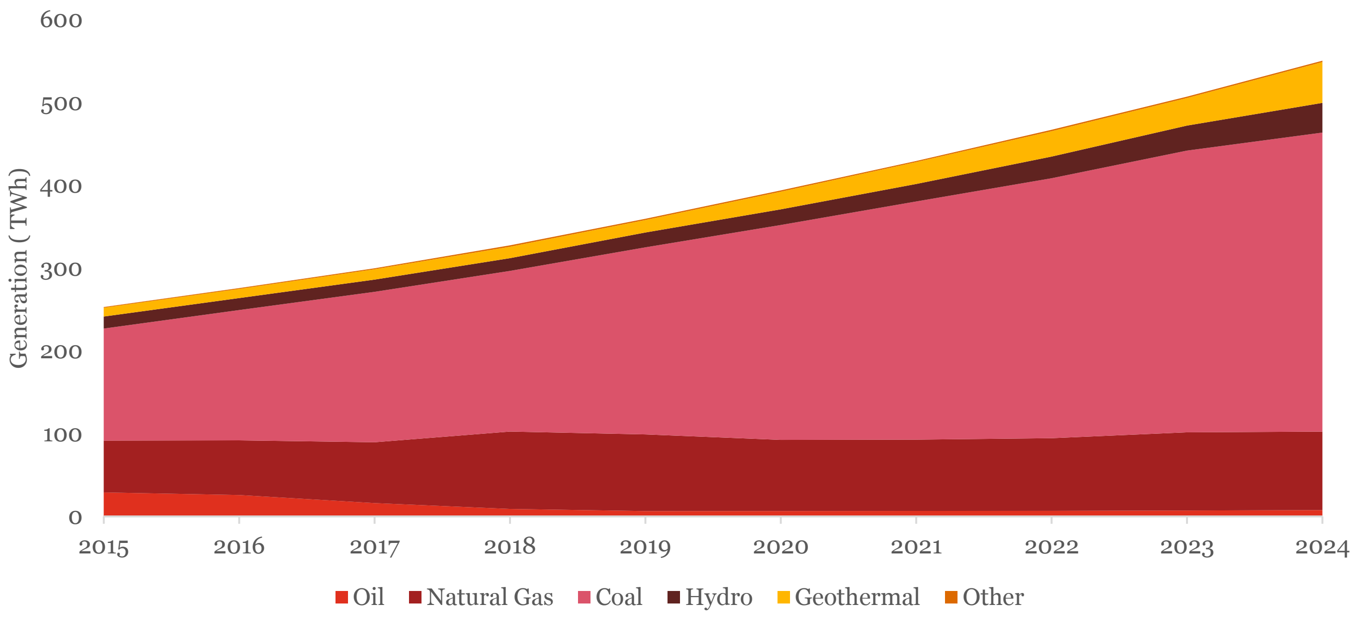
Scope	Total Number of Projects	Capacity
Generation	291	42,940 MW
Transmission	732	46,597 km
Distribution	1,375	108,789 MVA

Source: PLN, 2015

[13] Source: PLN Presentation "35GW programme" (excludes IDC and land acquisition)

Contribution of Coal in the 35 GW Programme

Figure 13: Electricity Mix in 2015-2024, TWh



Source: PLN RUPTL 2015-2024.
Note: Other renewable energy include solar/ hybrid, biomass, wind, account for 1.6 TWh of total generation 550 TWh in 2024

CFPPs are expected to contribute approximately 60% of power generation by the end-2019, compared to 53% in 2015

Based on the RUPTL, CFPP will be expected to provide the largest contribution to the power sector for the next ten years. The chart above shows the comparison between coal and different types of fuel mix such as geothermal, oil and natural gas that currently provide a significant contribution to the production of electricity in Indonesia.

We refer to two different types of CFPPs in this report:

- CMM: A plant built near a mine and relying on its supply. Often, the mine and the IPP are considered 'one project'.
- Other CFPPs, which may be geographically far from their supplier mines, and legally distinct.

Coal consumption at the end-2015, based on the National Medium-Term Development Plan ("RPJMN"), was 88 Mt. PLN has projected that the additional CFPP generation is likely to lead to additional demand for coal of approximately 79 Mt/year by end-2019 and approximately 85 Mt/year by end-2024. This is equivalent to around 4,000 tonnes of coal per MW per year. This would take total coal consumption in the Indonesian power sector, including existing CFPPs, to 166 Mt at end-2019 and 173 Mt/year at end-2024.

These estimates are included in our coal demand projections on pages 33 and 34.

Overview of 35 GW Programme
Progress to date

As at January 2016, 37% of capacity was still in the planning stage, 41% was somewhere between the PPA and the construction stage (not specified) and 22% was in the procurement stage.

There is a potential risk that the 35 GW programme may not be completed in time (December 2019) since for a typical IPP project, up to 69 months (5.8 years) could be needed to progress the 7,838 MW in the procurement/tender stage to C.O.D. Moreover, 13,267 MW has not yet been tendered.

Recognizing the risk of delay, the Government of Indonesia has implemented eight Acceleration Steps including relating to land acquisition for power generation, transmission, and distribution, tariff negotiation, IPP procurement process, permits, IPP developer and EPC due diligence, project management capacity, inter-ministerial coordination and legal issues.

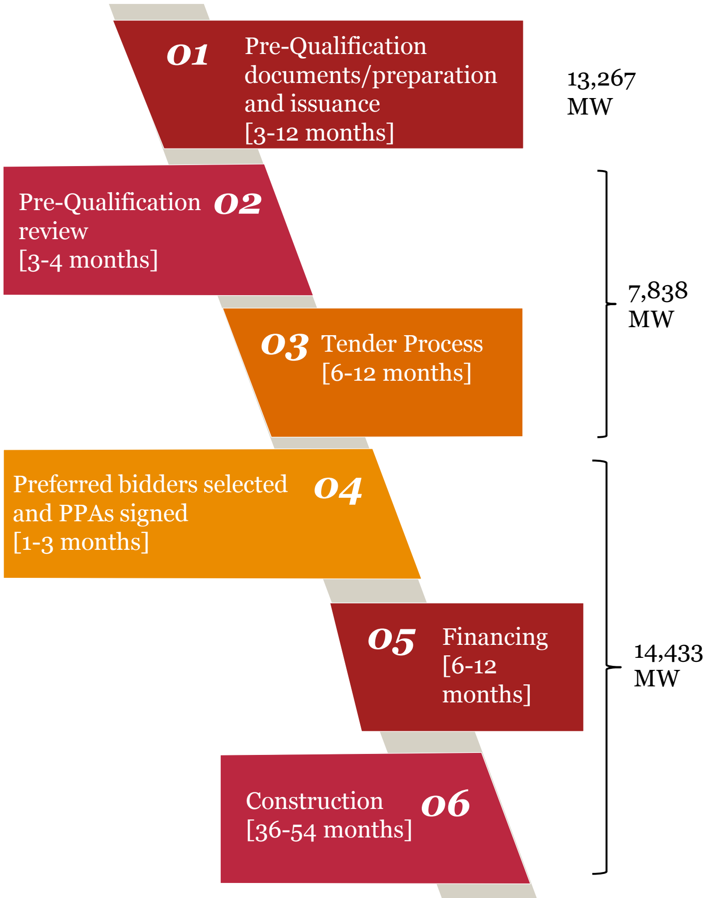
President Jokowi also approved PerPres No.4/2016 in January 2016. This PerPres aims to address the challenges specific to the 35 GW programme.

Under the PerPres, 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.

There are two key features of Perpres 4/2016 that should accelerate the development of the 35 GW programme:

- Government guarantee for power infrastructure development, which would cover both projects developed by PLN, and projects that are developed by PLN in partnership with PLN's subsidiaries or IPPs; and
- a shorter time period to obtain the required permits and non-permits.

Figure 14: Typical Timeline of Independent Power Producer Plant Development, Overlaid with Capacity from 35 GW Programme at Each Stage in January 2016



Source: PwC analysis in consultation with IPPs
Note: Stages are also broadly appropriate for PLN, EPC contracts as well as IPP tendering

Overview of 35 GW Programme
Acceleration steps

The Government and PLN have made significant steps taking forward the highly ambitious 35 GW programme.

Our interviews generated several suggestions to further accelerate the progress of the 35 GW programme.

1. **Land acquisition** is still a major bottleneck to the development of infrastructure projects in Indonesia, especially in the power sector. The main issue raised in interviews was the difficulty and/or expense for IPPs of obtaining land for generation and transmission.

   This affects transmission in particular. At the end of 2015, installed transmission was only 3,941 km compared to a planned 11,805 km[14].

   PLN should make full use of the provisions granted to it in PerPres No.4/2016, to acquire land. The recent equity injection could in part be used to develop greater financial and human resources dedicated to land acquisition.

2. **Funding** is a potential issue in the development of 35 GW of additional capacity. As stated on page 18, the amount of capital required for the 35 GW programme is \$73 billion. PLN is expected to provide \$34.6 billion (of which \$10 billion is for transmission), but is already significantly leveraged, with a Debt to Equity ratio in 2014 of 2.02x[15].

   Substantial financing is needed both by PLN and IPPs. PerPres No.4/2016 states the Central Government will provide a Government Equity Injection ("PMN") to PLN. This must not be delayed. A significant proportion of this equity could be used for investments that benefit both PLN and IPPs (e.g. transmission). Government Guarantees would likely help unlock greater sources of international finance.

3. **Licensing** for Coal Supply Agreement and spatial planning could still hinder projects. Many licenses for mining operations (IUPs and CCoWs: see page 45) are expected to expire in the early 2020's, well before the corresponding Coal Supply Agreements. In addition, IPPs have complained that Spatial Planning (and the need to wait for update thereof) could hold back other license issuance (e.g. AMDAL; Environmental Impact Assessment).

   To reduce concerns that Coal Supply Agreements are not aligned with mine permits, the Government should send clear signals that it will be committed to strategic IUPs for reputable miners supplying to domestic power plants. Or, the Government could insist that new miners in the same location must inherit the obligation to supply the power plant.

4. **Current IPP/PPA Procurement** procedures and conditions are not always streamlined or harmonized. RFPs for major projects have been repeatedly delayed.

   PLN should further standardize bidding documents for IPP procurement (e.g. template PPAs with minimal deviation from precedent).

[14] Source: esdm.go.id

[15] Source: PLN Presentation "35GW programme"

05

Methodology and Survey

Methodology and Survey

About the survey

APBI in conjunction with PwC held an anonymous survey of APBI members. The sample covered 25 producing companies.

The survey focuses on the producing segments of coal mining companies. The survey's results were extracted from a questionnaire that was carried out anonymously, built and disseminated online.

The objective of the survey was to capture key data on the condition of Indonesia's coal mining sector and reserves.

Survey respondents were asked to specify an answer within a range on their respective company's coal sales volume, mining Capex and coal reserves (variously 2015 and 2016).

Survey sample

The questionnaire was sent to all APBI members, and was strictly anonymous. Information about the sample obtained from the questionnaire is shown in Figure 15 and Figure 16 below, and the figures on the following page. The complete version of the questionnaire is included as Appendix 3.

To validate the key finding that reserves may have decreased by 29% on reported reserves (see Box 2 on the next page) we also conducted a short follow-up survey with the top ten miners (by production). Of the eight who replied, the production-weighted fall in reserves was 40%, if today's price was used as the assumption in future.

We use the 29% figure throughout the main results in this report, to be conservative.

Figure 15: Mining Location of Survey Respondents

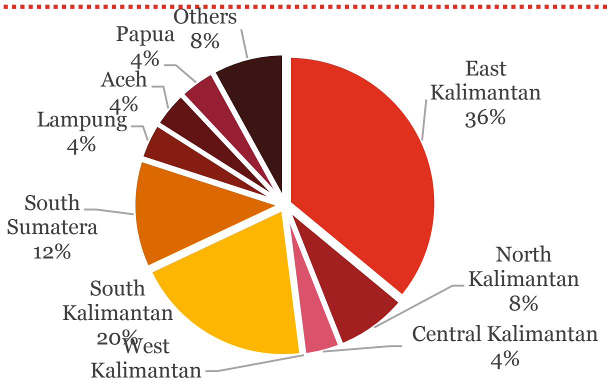
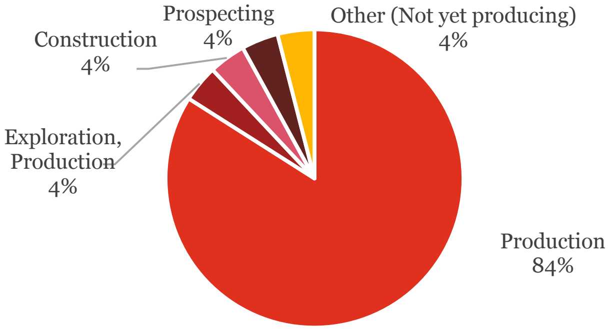


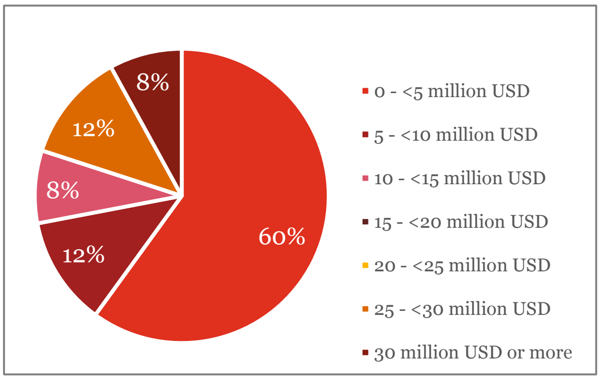
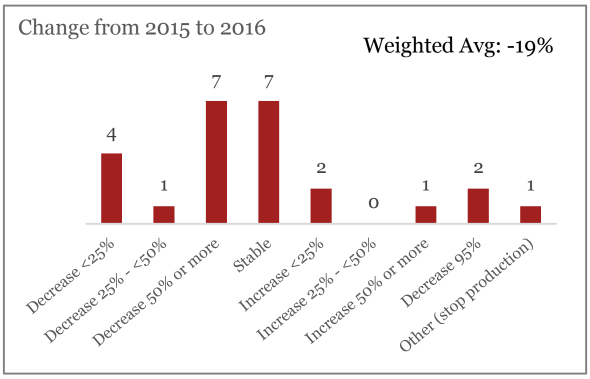
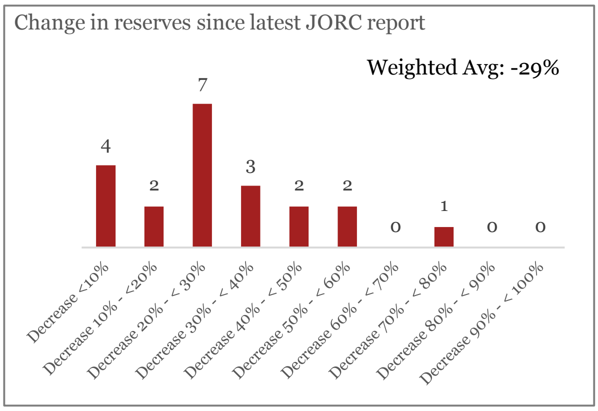
Figure 16: Mining Stage



Box 2: Our survey on coal reserves

The headline results were as follows:

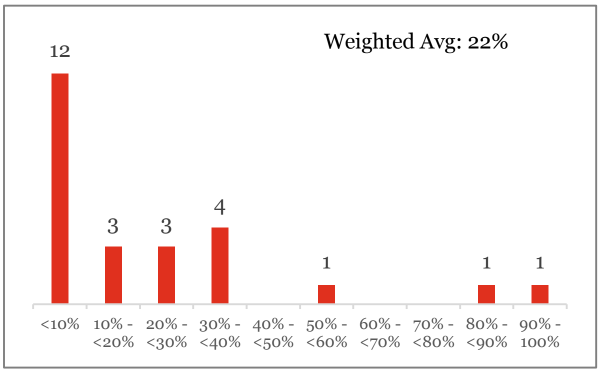
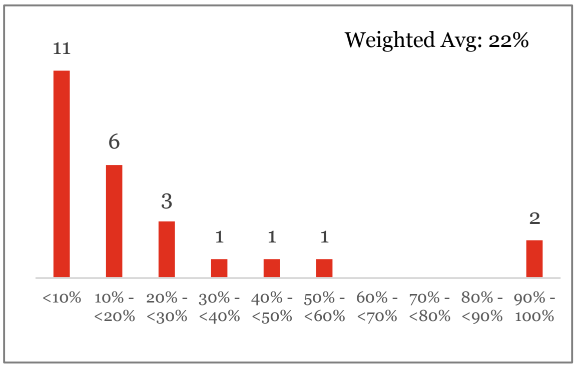
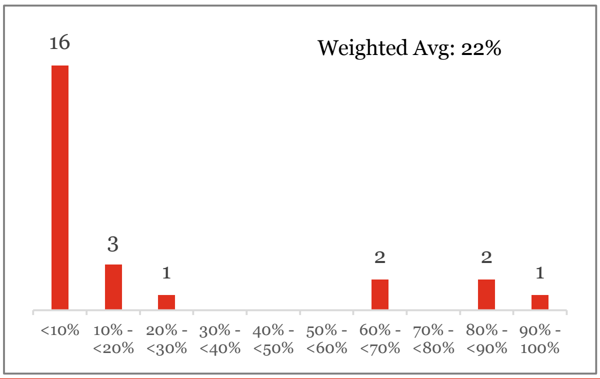
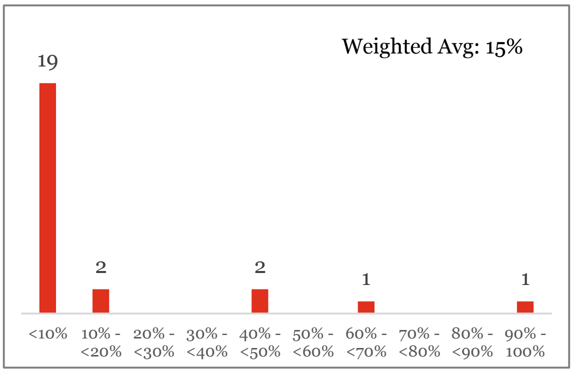
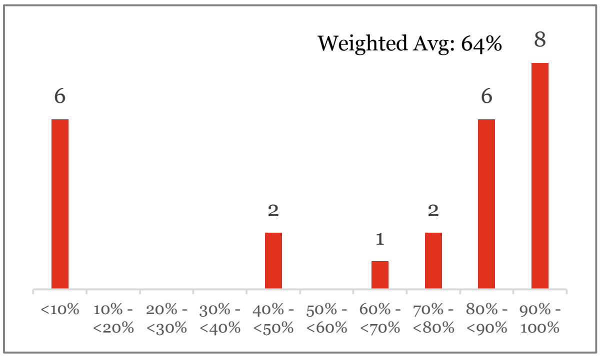
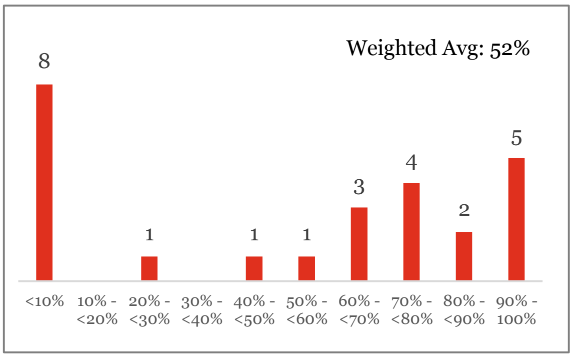
- Mining Capex will continue to decline; it is expected to decrease by a further 19% in 2016.
- Economically mineable reserves have decreased by 29% from the latest JORC reports, cited in Annual Reports (variously conducted between 2008 and 2012, and mainly between 2010 and 2012). This is consistent with the decrease in average HBA of 37% from 2012 to 2015.

<table>
<tr><th>Topic</th><th>Sample actual (2015)</th><th>Projected change</th></tr>
<tr><td>Capex</td><td>
</td><td>
</td></tr>
<tr><td>Reserves</td><td></td><td>
</td></tr>
</table>

Survey Results

Other Results

- The share of sales to domestic power plants in 2016 is expected to be similar with an average 22% in 2015.
- The share of sales to other domestic uses is expected to decrease from an average of 22% in 2015 to 15% in 2016
- The share of sales to exports is expected to fall from an average of 64% in 2015 to 52% in 2016.

Topic	Actual (2015)	Projected (2016)
Domestic Sales in Power		
Domestic Sales in Other Sectors		
Export		

Note: numbers do not add up to 100% due to confidentiality constraints preventing precise production numbers from being collected

06

Key Issues and Recommendations

Issue: Uncertainty around Coal Supply
Prices down and reserves falling…

Current situation: supply glut

Indonesian coal production has been heavily affected by the recent drop in coal prices (see Figure 17), that has led to some small-scale miners suspending operations, while big players have taken measures to protect margins and cash flows.

The drop in thermal coal spot price (to roughly $50.9/tonne in February 2016 from its peak of $127/tonne in 2011) has been caused by oversupply and weakening world demand, especially from China.

According to the Directorate General of Minerals and Coal at the MoEMR, the country's coal production in 2015 was 7% lower than the initial target of 425 million tonnes.

Looking ahead: uncertainty

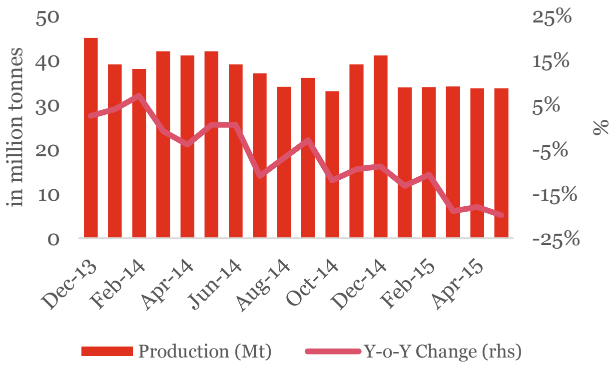
The Indonesian Government coal reference price (or HBA) for February 2016 was at $50.9/tonne, its lowest level since 2009 when the reference price was first enacted.

Some industry leaders remain confident Indonesia's coal industry will bounce back from this difficulty, especially with the 35 GW programme providing new demand and investment. Key export markets, including India, South Korea, Japan, and several countries in Southeast Asia are also building mostly CFPPs. For example, India overtook China in 2015 in terms of coal imports although India also plans to double coal production by 2020.

However, there remains huge uncertainty about future price movements. Environmental concerns, continuing declines in the cost of renewables, and over-supply in natural gas and oil markets mean medium-term and long-term demand for coal is not assured.

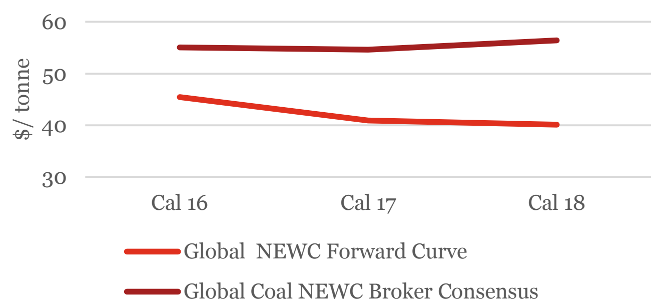
The forward curve (Global Coal NEWC) suggests prices for delivery in 2018 of around $40/tonne. Although later years are thinly traded, the market data suggest that market participants are not betting today on a strong recovery. Consensus forecasts from the beginning of 2016 suggest around $56/tonne is predicted up to end-2018

Figure 17: Indonesian Monthly Thermal Coal Production (Mt)



Source: Bloomberg, HDR Salva

Figure 18: Forward Curve and Broker Consensus Forecast as at January 21st 2016



Source: global COAL, APBI

Issue: Uncertainty around Coal Supply
… leading to reduced profits and investment

Profitability falling

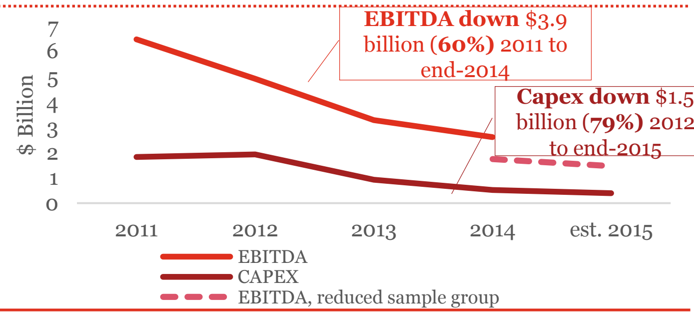
The fall in prices has had a clear impact on the bottom line. Operational costs have fallen to some extent (fuel typically accounts for 20-30% of opex) as oil prices have fallen since 2012, and significantly since October 2014 (see chart below).

Earnings Before Interest, Tax, Depreciation and Amortization ("EBITDA") of the mining groups listed on the Indonesian Stock Exchange ("IDX") was down at year-end 2014 compared to 2011. Aggregate EBITDA has fallen 60% since 2011, from $6.5 billion to $2.6 billion in 2014. Looking at a smaller group of companies, for which 2015 estimated data is available, EBITDA further fell by 16% from $1.7 billion in 2014 to $1.5 billion in 2015.

Aggregate Profits After Tax (i.e. including interest on loans, accounting for amortization and depreciation of assets, and tax accrued) have fallen from $3 billion in 2011 to $208 million in 2014, and three of the top 11 Groups are losing money after tax.

Smaller players, who are usually higher-cost than the larger companies, have suffered particularly. They disproportionately account for the fall in coal production mentioned on the previous page. Many have shut down (e.g. in Jambi), and reports of bankruptcies and layoffs are widespread[16].

Figure 19: Capital Expenditure and EBITDA from Listed Mining Companies



Source: Bloomberg and 2015 estimated. EBITDA 2011-2014 based on 11 Groups and 13 companies. EBITDA 2015 based on 9 Groups and 10 companies.

Investment falling

Unsurprisingly, the downwards trend in investment has tracked the downward trend in EBITDA:

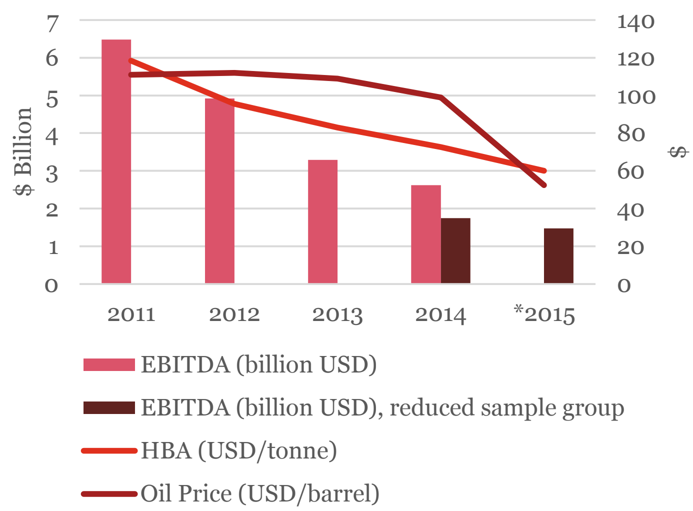
1. Capital expenditure has dropped by 79% since 2012 from $1.9 billion to an estimated $0.4 billion by end-2015.

2. The mining industry is expected to decrease Capex by a further 10-20% in 2016[17].

Most large companies are producing solely from existing mines and have already slashed their exploration activities.

Companies focused on exploration only (junior miners) have reduced investment activity significantly. For example, five companies exploring over 11,000 hectares in Tebo Regency, Jambi, declared bankruptcy in 2015. And, one of the industry's largest mining contractors, Delta Dunia Makmur has seen EBITDA fall 20% and Capex fall 69% between 2011 and 2014.

Figure 20: Oil and Coal Price to EBITDA



Source: Bloomberg
**) Notes: Data for 2015 based on LTM Sept 2014- Sept 2015*

[16] http://www.thejakartapost.com/news/2015/08/05/coal-miners-risk-going-out-business.html AND http://www.reuters.com/article/indonesia-coal-idUSL4N0991RB20121129 AND http://en.tempo.co/read/news/2015/05/25/056669066/Five-Jambi-Coal-Companies-Go-Bankrupt

[17] Source: Two questionnaires to APBI members finding 10%, and 19% (this survey) respectively

Issue: Uncertainty around Coal Supply

Companies holding one-third of reserves have very low per tonne profitability

Low average profitability hides variation: companies owning 40% of reserves are likely operating near the marginal break-even point

The chart below shows EBITDA per tonne for the top 11 mining Groups (which includes 13 companies). **Around 40% of reserves are held by companies that, at year-end 2014, were earning less than $6/tonne before interest, depreciation/amortization and tax** (see Figure 21 below).

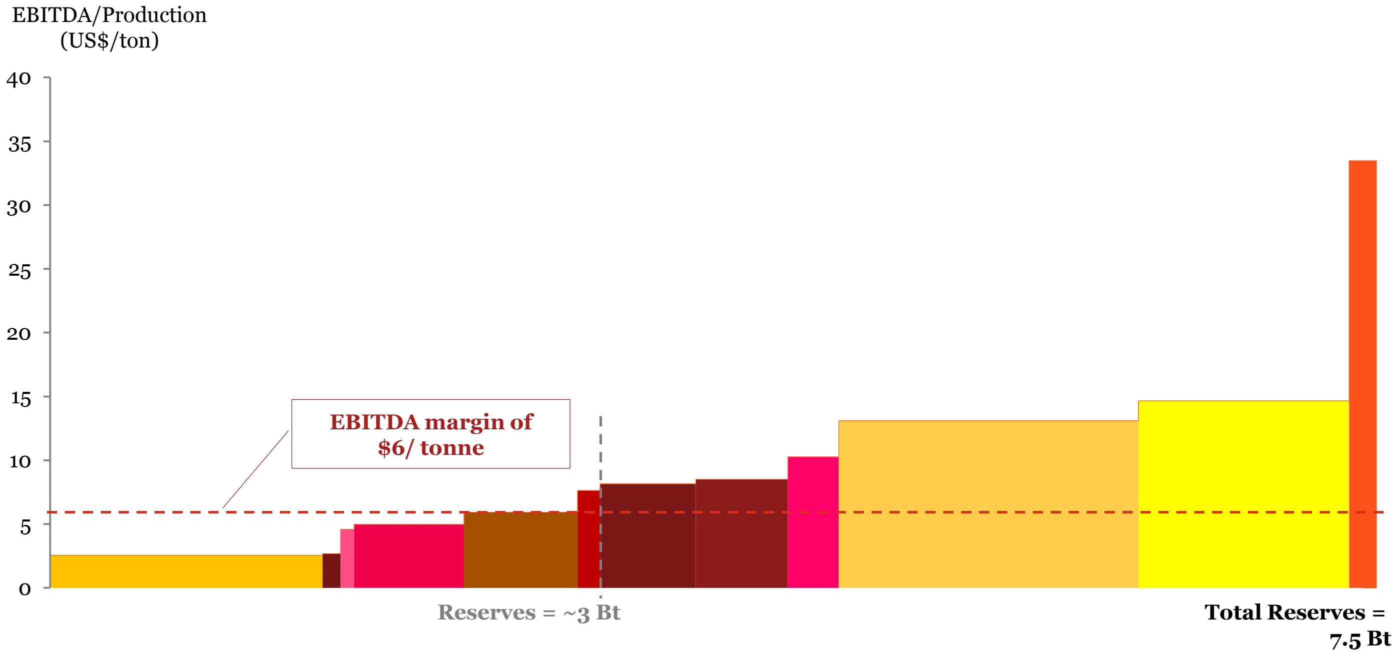
The HBA price has fallen by around $46/tonne or 39% from 2011 to 2014. There is a mild offsetting effect from fuel costs: diesel prices have fallen by around one-third over the same period.

But, fuel costs on average make-up around $5/tonne [18] and so this offsetting impact is limited to a $1-2 tonne cost reduction.

Not accounting for currency depreciation effects and other changes in costs, this implies around a $9 fall in EBITDA/tonne since 2014 (see Figure 21 below). Indeed, for most of those companies who have released 2015 data, EBITDA has fallen again since the end of 2014 (see previous page).

Companies have also been reducing stripping ratios to maintain margins, but this can have an adverse impact on reserves (see page 31).

Figure 21: Industry Profitability compared to Reported Reserves (2014)



Source: Bloomberg (and Bloomberg methodology applied to Annual Report of a group where data unavailable). Total reserves from the Top 15 Mining Companies are around 8.1 Bt (see page 34). The total reserves do not add up to 8.1 Bt because two companies are excluded.

[18] Source: http://www.marston.com/Portals/0/Marston_Presentation_FINAL.pdf (2008). At the time of publication oil prices were around $100-130/ barrel, even higher than end -2014 ($60/barrel)

Issue: Uncertainty around Coal Supply

Combined with high leverage, capacity to invest is severely constricted

Levels of leverage have risen dramatically…

Overall leverage (the amount of debt a company owes and its ability to pay it back) has also risen over the past few years. The average Debt to Equity (Book Equity) ratio has risen from 1.1x to 1.3x between 2011 and 2014 (see Figure 22). Similarly, the average Debt to EBITDA ratio increased from 1.5x to 4.0x over the same period.

Based on estimated Last Twelve Months ("LTM") data from the first three quarters of 2015, leverage on both counts rose again. Debt to Equity rose to 1.4 and Debt to EBITDA rose to 4.6. This is in the context of some mining groups paying off debt, too.

While not every company has large levels of debt, the sector as a whole may face problems accessing finance for new investment projects. Non-performing loans in the whole economy increased significantly from 12.2% to 35.1% between 2014 and 2015, largely due to the mining sector [19].

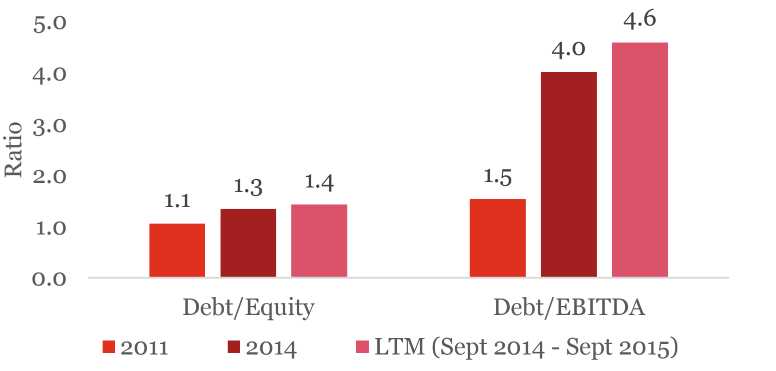
… and equity remains difficult to access

The total market capitalization of the top eight mining Groups in 2015 was $6.5 billion, down from $33.4 billion in 2011.

With a market capitalization of only $6.5 billion the dilutive effect of raising $7-9 billion of equity for capital expenditure would be significant. It is unlikely to be feasible to raise this level of equity in the short term given the equity base.

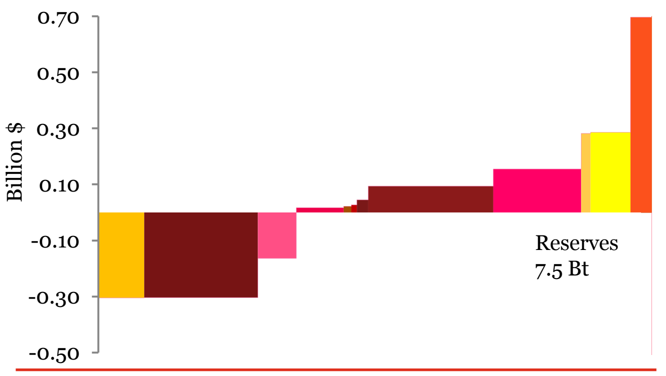
The lack of capital can also lead to a vicious circle. Even cost-reducing investments such as in new technology, processes and more efficient transport infrastructure may be unaffordable, meaning margins are unable to improve without prices recovering, constraining future investment, and so on.

Figure 22: Debt to Equity and Debt to EBITDA (2011, 2014 and LTM up to September 2015)



The chart is based on the top ten coal mining companies (nine groups). Note one Group has negative book equity. Care must be applied when interpreting debt metrics. For example, some mining companies borrow/lend to other companies within the Group.
Source: Bloomberg (Bloomberg methodology applied where data unavailable). One company's LTM 2014-15 data was based on the Annual Report, as Bloomberg's est. lies outside the expected range and differs significantly from management estimates.

Figure 23: Profit After Tax ("PAT") to Reserves,2014



Source: Annual Report. Excludes 2 companies that belongs to 2 groups.

[19] Source: http://www.tribunnews.com/bisnis/2015/11/13/kredit-macet-bertambah-akibat-sector-pertambangan-melemah

Issue: Uncertainty around Coal Supply

Companies are slashing operational costs. Insiders suspect that sterilization of reserves may be taking place

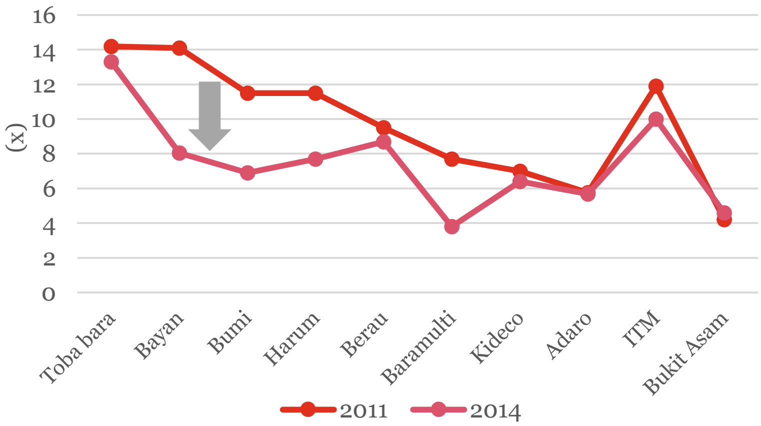
Responses to the low price environment may make some future reserves unrecoverable

Companies have taken a number of measures to maintain profitability despite low prices, including layoffs of workers and cutting back on capital expenditure, and negotiating with mining contractors on rates.

A core cost driver in the Indonesia mining industry is the Stripping Ratio: the amount of bcm overburden (i.e. soil) needed to be removed to extract one tonne of coal. Reducing the stripping ratio by focusing on shallow coal immediately reduces extraction costs.

Industry appears to be doing this. Based on a sample of 11 mining companies for which data was publicly available, in 2011 the average stripping ratio was 9.7x. Since then, the average stripping ratio has plunged, and was around 7.5x in 2014. Stripping ratios have likely continued to fall in 2016 (e.g. Adaro: 4.7x in 2016 from 5.2x in 2015) [20]. And, this is likely to be an underestimate since companies with the highest stripping ratios may have already stopped operating.

Figure 24: Average Stripping Ratio (2011 and 2014)



Source: Annual Reports and Investor Presentations

Changing mine plans now to reduce stripping ratios in response to lower coal prices will lower mine lives and total reserves. Some analysts have already highlighted this as a near-term possibility for some Indonesian miners[21].

Reserves that were economically viable at the time of reserve certification in earlier years at higher coal prices may not be economically sustainable, and could therefore be abandoned.

In addition, where miners have operated at lower stripping ratios in early years, operational factors may make it technically difficult (or even impossible) to recover later reserves at *any* stripping ratio (e.g. operational reasons, health and safety concerns).

The effect can be non-linear. Backfilling means that the same overburden may have to be extracted twice. Inevitably, this raises the life of mine (average) stripping ratio and renders future reserves less likely to be economically viable.

As discussed on page 34, economically mineable reserves are estimated to have decreased 29% from 11.7 billion tonnes in 2012 to 8.3 billion tonnes at the end of 2015[22].

Sterilization of reserves is explained further in Box 3 on the following page.

[20] Source: Adaro's 2014 Annual Report & Adaro Energy 4Q15 Quarterly Activities Report

[21] Source: http://www.trimegah.com/data/files/trim_sf_2-0141030_coal_profitability_vs_sustainability_1.pdf

[22] Source: APBI's survey

Box 3: Sterilization of reserves explained

Moving waste material and overburden (i.e. soil) to recover the coal is known as stripping. The 'stripping ratio' represents the volume of waste material or overburden to obtain one unit of coal mined. A stripping ratio of 1:7 means that, over the life of mine, the miner will have to remove seven bank cubic metres ("bcm") of overburden to extract one tonne of coal.

The stripping ratio is strongly influenced by the market price of coal as well as other production costs. The higher the coal price, the higher the stripping ratio that would be economically viable.

The Mine Plan sets out an optimal trajectory for the stripping ratio over the life-of-mine, maximizing value extracted. However, in times of financial stress, miners may lower the stripping ratio below the optimal level set in the Mine Plan to recover lower-cost coal more quickly. This is likely to make future reserves more costly to extract, or even uneconomical to extract using current technology, which can result in 'sterilization' of remaining reserves from the mine plan.

We set out a simple example below with illustrative numbers to explain:

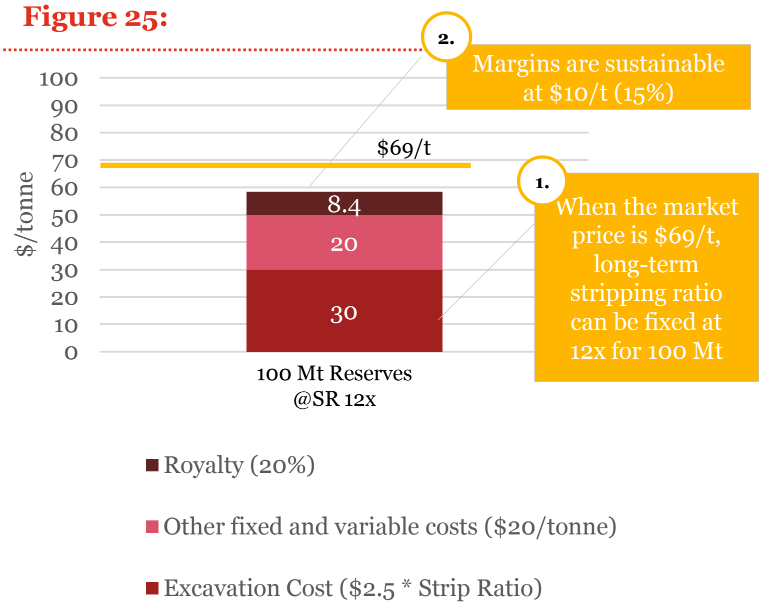
1. Based on an expected market price of $69 the Mine Plan for extraction of 100 million tonnes of reserves may set the average stripping ratio at 12x (or 12:1).

2. This accommodates excavation costs directly proportional to the stripping ratio (assumed $2.5/bcm) of $30/tonne, other fixed and variable costs of $20/tonne, and a royalty of 20% (as stipulated for CMM supply), leaving a simple margin of $10/tonne.

3. However, if the market price moves to $55, then to maintain margins in the short-term, the miners may reduce the stripping ratio to 8x for the first 50 million tonnes extracted.

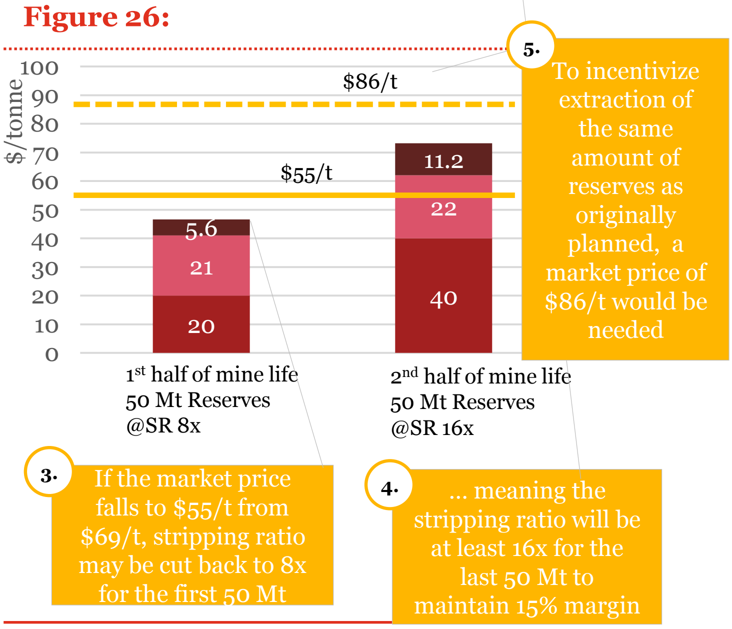
4. This implies that for the next 50 million tonnes, which may be required to be extracted at 16x (or higher if overburden has been disposed of within the mine site) the market prices needs to reach at least $86/tonne for the miner to continue production and maintain the same 15% margin. Furthermore, these reserves may not be mineable at all for operational reasons or due to health and safety concerns. So, lower prices would indicate that reserve estimates would be lower today, than when initially estimated using a mine plan with higher stripping ratios at higher coal prices.

Figure 25:



Source: PwC analysis

Figure 26:

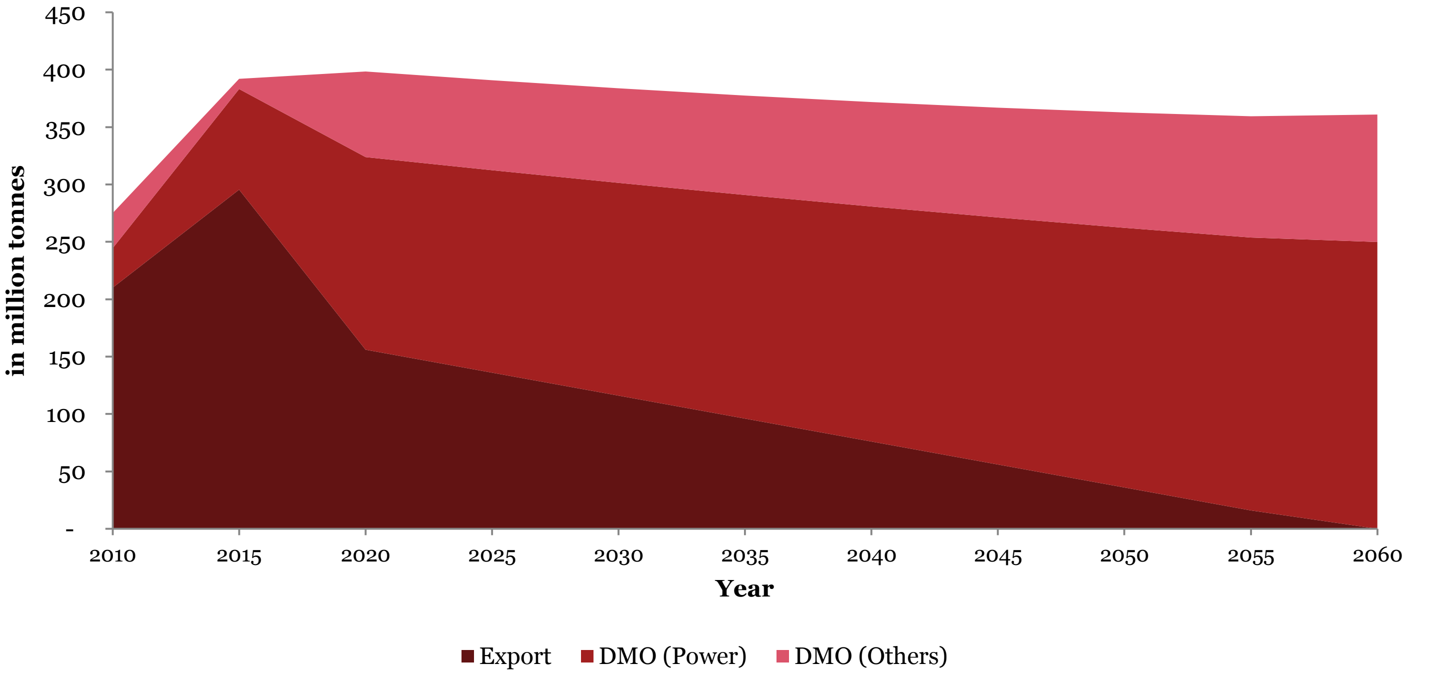


Source: PwC analysis

Issue: Uncertainty around Coal Supply

If production remains at around 350-400 million tonnes a year…

Figure 27: Coal Production 2010-2060 (projected)



Source: MoEMR, Bappenas, APBI, PwC analysis

Production is likely to remain between around 350 and 400 million tonnes a year

Based on market trends and Government targets, we have constructed a simple demand scenario for Indonesian coal. This is based on the following assumptions:

- Coal production follows RPJMN targets until 2019. This assumes the implementation of the 35 GW programme by end-2019.
- After 2019, exports decline gradually by 4 Mt/year, bottoming out at zero million tonnes in 2059.
- After 2019, domestic power and other demand continues to rise gradually, slower than economic growth, at 1% a year.

Figure 28: Details of Demand Scenario 2019-2050

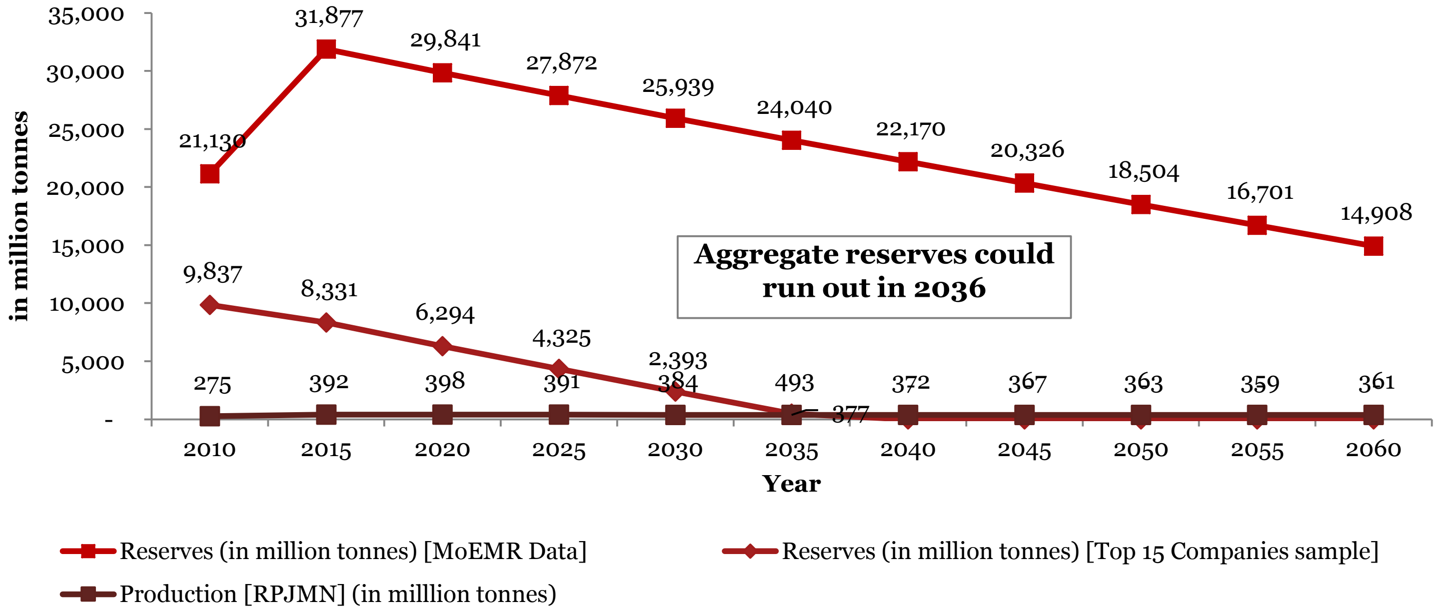
Million tonnes	2019	2024	2030	2050
DMO (power)	166	175	185	226
DMO (other)	74	78	82	101
Export	160	140	116	36
Total	400	393	383	363

Source: MoEMR, Bappenas, PwC analysis. DMO = Domestic Market Obligation (see page 47).

Issue: Uncertainty around Coal Supply

... then reserves could only last until end-2036

Figure 29: Coal Reserves, Production, and Demand 2010-2060 (projected)



Source: Annual Reports of Coal Mining Companies, PwC Analysis, APBI Survey, MoEMR

Government data suggests that coal reserves will last until 2094

Based on this level of demand, and MoEMR-published data on reserves (32.3 billion tonnes in 2014), aggregate reserves would be expected to run out in 2094. This is a simplification as different ranks of coal have different markets and reserve volumes. However, in the absence of more detailed data, we have looked at this in aggregate only.

But using private sector data and our survey results, the reserves could run out in 2036

The MoEMR reserves data are not published alongside a detailed methodology and underlying data sources, which makes it difficult to validate the information. At the same time, published reserves have not responded to large changes in the market price in recent years. Looking instead at private sector and State-Owned Enterprise data on economically mineable reserves paints a different picture.

The reserves of the top 15 coal mining Groups in Indonesia totalled 7.9 billion tonnes in 2012, based on Annual Reports (the equivalent in 2014 is 8.1 billion).

These Groups account for 67% of average production between 2012 and 2014, and so scaling-up reserves pro-rata suggests total company reserves of around 11.7 billion tonnes in 2012. Again, this is a simplistic method, as recent production may not be an accurate predictor of total reserves.

Even so, this data is already 18 months old, and many Annual Reports are based on JORC reports from 2008-12. Downward movements in the market price of coal since then would be expected to reduce economically mineable reserves.

Our survey of APBI members suggests reserves are 29% down from the reported figure of 11.7 billion tonnes; this implies total reserves of 8.3 billion tonnes at the end of 2015. Based on the demand scenario in Figure 28, **then aggregate reserves would run out in 2036.** This demand scenario is conservative as it assumed rapidly declining exports: IEA predicts exports alone of more than 300 Mt by 2025[23].

And, given CMM power (around 18% of planned power plants) reserves are effectively secured for 25 years, this implies that reserves for the non-CMM power plants could run out in 2035. And, as discussed on page 24, a second survey of the largest miners suggested a drop in reserves of 40%, which would imply the reserves lasting until only 2033.

[23] Source: Southeast Asia Energy Outlook 2013, IEA

Recommendation: Cost-Based Pricing

Consider moving to long-term, cost-based pricing as insurance against supply shortages

Moving to cost-based pricing

From our interviews, there was a broad consensus that the current regulatory structure and pricing levels for CMM power plants is fair for miners and fair for the Government. The regulation facilitates the extraction of reserves that:

- have little alternative economic use (on account of their low calorific value relative to transport costs); but,
- still represent one of the cheapest ways for PLN to generate power and draw on an abundant domestic resource.

Given current market conditions, it appears that there is a valid argument to extend similar regulation to all domestic CFPPs to be built under the 35 GW programme. Export pricing and non-power Domestic Market Obligation ("DMO") pricing would remain unchanged.

At its core, the regulation would set out a long-term cost-based structure for thermal coal, to be used as a contracting basis between the coal procurer (IPP or PLN) and the coal miner. This cost-based pricing is just an option for developers, and not anticipated to be mandatory for all coal pricing.

The cost would be based on best-in-class benchmark costs, with escalation factors to be reviewed on a periodic (say five-yearly) basis. The benchmark cost would be expected to mainly be a function of stripping ratio (per bcm overburden).

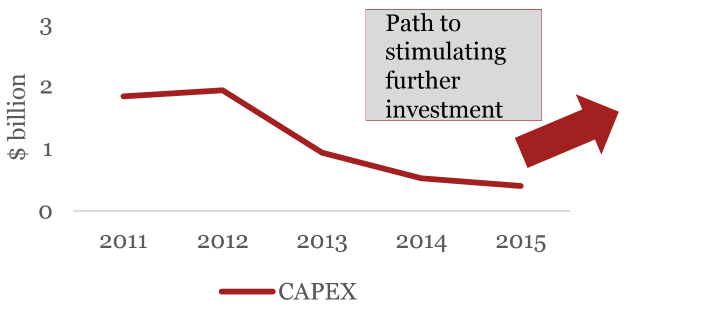
It is envisaged that the cost-based price would be higher than the current HBA/HPB benchmark (see page 48) for a comparable stripping ratio, since the current market price does not appear sufficient to secure reserves for the 35 GW programme.

In effect, the Government of Indonesia would be paying an 'insurance premium' now to take out a policy to protect itself from a future reserve crisis and the need to import (if coal prices fail to recover) or to protect itself from rising power prices (if prices recover). Thus, security and cost are balanced.

Stimulate further investment

By providing miners with predictable and stable returns, the policy would likely drive a recovery in investment in the mining sector, encourage life-of-mine planning rather than beholding stripping ratios to the market price, and stabilize economically mineable reserves. If combined with adequate incentives for IPP investment (our interviews suggested that a hurdle rate for Project IRR by mining companies is around 10-12%), this recovery in mining balance sheets could also drive new investment in IPPs, too.

Figure 30: Capital Expenditure and EBITDA from Listed Mining Companies



Source: Bloomberg

Recommendation: Costs of the Policy

Consider moving to long-term, cost-based pricing to balance security and cost

Direct costs of the policy

In the absence of location-specific cost and demand data, we do not take a view on what the 'right' price or prices should be to balance security of reserves and minimize cost.

However, using the current CMM costs as a proxy for a cost-based price, we have estimated an illustrative cost to PLN (and ultimately the Ministry of Finance) of the policy:

- Based on various benchmarks for life-of-mine stripping ratio and Calorific Values ("CV") (GAR), the additional coal procurement cost in January 2016 could be around $6.9/tonne (see page 37).
- If the policy only applied to new power plants (around 15 GW)[24] in 2019, around 60 Mt of coal would be required each year. The total incremental annual cost to PLN as compared to the 2020 price would be around $414 million, or 0.12 c/kWh for the end customer in 2020.
- If the policy applied to all power plants expected to come online in the long-term (around 40 GW) then 160 Mt of coal would be required each year and the total incremental annual cost to PLN as compared to the 2020 price would be around $1.1 billion, or 0.33 c/kWh for the end customer in 2020.

The scope of this cost is uncertain (depending on whether applied to all or only new power plants, and for how long), but would be partially offset by increased royalty revenue. For example, if the 29% reduction in reserves (3.4 bn tonnes) were recovered, then this would amount to 340 Mt of extra production for ten years. Based on 2015 data, this might be expected to increase royalties by $1.1 billion/year for that ten-year period[25]. This benefit exceeds the annual cost mentioned above, at least over the ten-year period mentioned (see page 38).

The average difference across the range of CVs and SRs presented represents a **1.2% - 3.2% increase in a representative power tariff of Rp 1,400/kWh.** This is around 0.5%-1.5% of total capital expenditure required for the power programme ($73 billion). For some households on lower tariffs (see Figure 39 of Appendix 2) this would be more like a 4-5% increase, although special pricing could be retained for poorer households.

Changes in the input assumptions would heavily influence the results. For example, a rise in HPB to $65/tonne would result in a cost saving to PLN of $1.5 billion and a reduction in consumer tariffs relative to current policy of 0.47 c/kWh. Reductions in the regulated 'cost-based price' would have the same effect.

To set the price that is fair for both Government and miners, a full assessment is needed of reserve data and production costs. This would require additional data to be collected by the MoEMR or APBI.

[24] PLN Market Sounding (2015). Of the 20 GW of new power plants, around 5 GW are already at the PPA stage, which suggests Coal Supply Agreements will be finalized soon, with pricing based on current regulation.
[25] Total domestic production and total royalties in 2015 = $3.1/tonne

Recommendation: Costs of the Policy

The cost to Government to secure supply could exceed $400 million/year, relative to projected 2020 coal price

Illustrative Cost Under Coal Mine Mouth Regulation (DoGMC 953.K32/DJ/2015)									
Stripping Ratio	#	1.6	1.9	2.1	3.0	3.5	4.0	5.5	8.1
Overburden Hauling Distance	Km	2	2	2	2	2	2	2	2
Coal Hauling Distance	Km	40	40	40	40	40	40	40	40
Coal Transportation Distance	Km	1	1	1	1	1	1	1	1
Direct Costs	$/tonne	14.86	15.51	15.59	17.9	18.99	20.07	23.33	28.97
Indirect Costs	$/tonne	6.69	6.69	6.69	6.69	6.69	6.69	6.69	6.69
General and Administrative Expenses	$/tonne	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Sub-Total	$/tonne	21.76	22.41	22.49	24.80	25.89	26.97	30.23	35.87
Margin	25%	5.44	5.60	5.62	6.20	6.47	6.74	7.56	8.97
Sub-Total	$/tonne	27.20	28.01	28.11	31.00	32.36	33.71	37.79	44.84
Port Stockpile + Loading to Barge	$/tonne	4.00	4.00	4.00	5.00	4.00	4.00	4.00	4.00
Total F.O.B Barge	$/tonne	31.20	32.01	32.11	36.00	36.36	37.71	41.79	48.84
Average (A)	$/tonne				37.00				
Average difference price (A-B)	$/tonne				6.90				
		Low (15 GW)				High (40 GW)			
Total Projected Coal Consumption in 2020	tonnes	60,000,000				160,000,000			
TOTAL INCREMENTAL COST	**$**	**414,248,250**				**1,104,662,000**			
PLN Sales in 2020	MWh	332,000,000							
Cost per kWh consumed	**$/MWh**	**1.25**				**3.33**			
	$ c/kWh	**0.125**				**0.33**			
Increase in an example power tariff of Rp 1,400/kWh		1.20%				3.21%			

Illustrative Cost Under HPB Benchmark (January 2016 Projected to 2020)								
GAR (Kcal/kg)	2,500	3,400	3,800	4,000	4,300	4,500	4,600	6,000
TM (%)	50.10	48.00	40.00	38	32.00	35.00	28.00	15.10
ASH (%)	5.30	7.00	5.23	6.00	6.00	4.96	7.00	9.40
Sulphur (%)	0.60	0.70	0.15	0.50	0.50	0.50	0.50	0.56
Total F.O.B Barge (2016)	13.15	15.12	20.24	26.86	30.34	31.38	34.69	49.13
2016-2020 Price Increase	9%	9%	9%	9%	9%	9%	9%	9%
Total F.O.B Barge (2020)	14.33	16.48	22.06	29.28	33.07	34.20	37.81	53.55
Average (B)				30.10				

Source: Based on DGoMC Circular Letter No. 953.K/32/DJ/2015 (low end of range), illustrative operational assumptions, and MoEMR HPB Benchmark January 2016. 9% uplift based on Broker's Consensus (extrapolated).

Illustrative Royalty Calculation; offsetting costs	
Coal sales revenue ($)	9,433,605,035
Royalty ($)	943,360,503
Royalty/ tonne ($)	3.1
Assumed recoverable reserves under cost-based pricing	3,400,000,000
Production/year (tonnes), for a ten-year period	340,000,000
Incremental royalty/year for ten-year period ($)	**1,062,686,236**

Source: Revenue based on APBI data from 2015. Assuming average royalty of 10%.

Recommendation: Costs of the Policy

Consider moving to long-term, cost-based pricing to balance security and cost

Benefits of the policy: Avoided costs

While the policy would likely entail a direct cost to the Government/PLN in the short-run, there are several potential avoided costs from alternative scenarios:

1. **Substitution for gas:** If only 15 GW of the plants could not source coal after 2036, gas may be used instead. This would likely cost around $5.9 bn/year (vs. $2.5bn/year for cost-based coal, assuming $42/tonne for 3,700 kcal/kg GAR). This estimate looks at the marginal fuel cost only: it assumes gas plants/network have spare capacity and therefore excludes significant generation and transmission costs, as well as the Component A Capacity Charge that PLN could be left paying for stranded coal generation assets [26].
2. **Importing coal:** A supply shortage of coal could require importing of coal from Australia. Between January 2011 and 2015, the Newcastle benchmark traded around 6% higher than HBA for the same Calorific Value, and shipping costs from Australia to Indonesia are in the range of $15-25/tonne. Given Indonesia accounts for 41% of the global seaborne market, supply disruptions would likely lead to a large increase in the price of international coal [27].

Accounting for Indonesian shipping costs required for cost-based pricing anyway, the incremental costs of coal importing could amount to some $10-20/tonne. And, this excludes problems associated with retrofitting plants designed for lower Calorific Value, and upgrading ports and logistics infrastructure to handle traditionally larger Australian vessels.

[26] Assumption: Gas plants operating with thermal efficiency of 60% compared to subcritical coal of 38%. Gas price $10/MMBtu.

[27] http://www.rba.gov.au/publications/bulletin/2015/jun/pdf/bu-0615-3.pdf

Recommendation: Costs of the Policy

However, other outcomes may be more expensive for the public sector

Alternative options

In addition to these 'Business As Usual' scenarios, one alternative proposal to achieving the objective of security of coal supply was raised during the interviews for this project: recalibrate the 35 GW programme and expand transmission capacity.

It was suggested to increase the number of CMM plants in Kalimantan and Sumatera, avoiding transport costs and rendering viable again many coal reserves. Regulation in this case would not need to be revised.

However, given low demand in Kalimantan (Peak Demand of 3 GW in 2019), significant transmission capacity to net importing regions (i.e. Java-Bali, 2019 Peak Demand of 34 GW) would be required. Covering the 700-800km between Kalimantan and Java with subsea transmission cables would, however, be an engineering challenge of unprecedented magnitude in Indonesia [28].

Additional capacity in Sumatera is more feasible given demand (Peak Demand of 9 GW in 2019) and distance/geography. The planned Java-Sumatera transmission link is designed at 1,600 kVA (expected to handle 4-5 GW). But, with Java still expecting 15 GW of new coal capacity before 2019, another *three projects* of the same magnitude would be required[29]. The amortized cost could be around $700 million/year even assuming financing could be found[30]. It is not clear if this solution is technically possible given the need to balance the load across grid systems. This simple comparison also ignores likely large voltage losses over such long distances.

Redesigning the 35 GW programme would wreak havoc in current planning and procurement processes. We therefore take the existing 35 GW generation and transmission configuration as a given. In any case, increasing the number of CMM plants would effectively increase the coal cost by an amount comparable to the suggested policy.

[28] Source: MoEMR RUKN

[29] Source: PLN Market Sounding (2015). 4.9 GW of PLTU are marked as already at PPA/LoI stage and we assume their Coal Supply Agreements are already finalized.

[30] Based on the existing Java-Sumatera feasibility study, and assuming 10% discount rate and 20 years amortization period.

Recommendation

Build in policy safeguards to protect the public sector

Safeguards will be required to protect taxpayer value-for-money and avoid further distortions in the market

Policy should aim to achieve the primary objective in the most cost-effective manner possible. Given opacity in the Indonesian coal market (cost and price data are closely guarded), and the wide dispersion in costs by geography and geology, it is crucial to:

1. Consult widely before establishing new cost bands for coal for thermal power generation

2. Ensure incentives are in place to minimize future costs to the public sector (PLN, Ministry of Finance)

Suggestions to this effect from the stakeholder interviews conducted during this project included:

- **Competitive pressure must be maintained in coal supply bids:** To avoid coal miners simply using high-production cost coal for domestic power and exporting low-production cost coal (which, holding CV constant, would simply raise the cost of coal without necessarily increasing the security of supply for PLN), multiple bids must be encouraged (or mandated) so that competitive pressure is maintained. The MoEMR could also reserve the right to regulate maximum production cost before approving the coal price, based on the mine plan (as is true at present for CMM coal).

- **Regional differentiation:** It is unlikely that a single national price will minimize the cost given varying cost conditions. Further analysis on costs in key provinces (e.g. East Kalimantan and South Sumatera), power demand and technical specifications of power plants, would assist in guiding the price setting.

- **Make the long-term commitment credible on both sides:** The flip-side of industry having volume and price commitments for a 20-30 year period is that industry forfeits the chance to export coal at the spot price. If the international coal market booms again, domestic contracts must be credibly enforceable. The use of deposits, penalties, guarantees or cross-shareholdings could help decrease incentives to renege on supply contracts.

- **Incentivize cost reductions:** Allow depreciation of capital expenditure at actual costs (not benchmark costs) that sufficiently reduce the costs of mining. Consider benefit-sharing between the Government and miners of operational cost reductions, and allow periodic (say five-yearly) reviews of cost weights for escalation factors to keep costs in line with the market.

- **Plan transport for the long-term:** Rail is generally speaking significantly cheaper than road transport over sufficient distances (say, over 100km). Increased Government support for key coal rail projects in Kalimantan and Sumatera would likely reduce long-term pre-unit costs.

Issue: Limited Sources of Investment

Miners can only invest a limited amount in IPPs

The natural equity providers for Indonesian infrastructure have limited capacity to invest

This report has commented on the need for coal supply and contract security, partly through increased shareholdings between mine and power plant owners. For CMM projects, MoEMR Regulation 10/2014 already requires a 10% shareholding in the IPP by the mine for this reason.

More broadly, coal mining companies are arguably a natural source of equity for CFPPs:

- Investing in IPPs helps mining firms diversify their revenues and is a hedge against commodity prices.
- It also helps PLN and the Government reduce contract default risk and enhance security of coal supply.
- It provides an incentive for miners to manage their reserves effectively and accurately assess costs in advance.

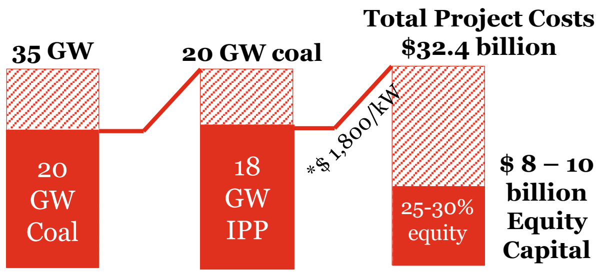
But, the equity requirement is very large. As discussed on page 18, the 35 GW programme is expected to require around $73 billion in investment. The private sector component of this is around $38.4 billion[31].

These projects are often financed under limited-recourse Project Financing or similar structures but with parent company guarantee. Typically Debt to Equity ratios are between 70:30 and 75:25**. This implies that around $8–10 billion in new equity capital is needed to support these projects before the end of 2019.**

Yet the sector today could not afford to invest more than a fraction of this. The total market capitalization of the top eight mining Groups in 2015 was only $6.5 billion, down from $33.4 billion in 2011. Debt capacity is also limited for most mining companies (see page 30). Total capex in 2015 was only 4%-5% of the required $8–10 billion.

To some extent, providing a fair, long-term price for coal for domestic power consumption would shore up balance sheets. In addition to funding new coal exploration, this improved financial position could boost the ability of the mining sector to provide equity to downstream IPP projects.

Figure 31: Illustrative Diagram of Required Investment for CFPP in 35GW



**) Source: Based on EPC costs of $1,300/kW + owner's costs of 500.*
Source: PwC analysis, validated by stakeholder interview.
Note: Capex estimated very significant by project, this is representative average

[31] Source: PLN Presentation "35GW programme"(exclude IDC and land acquisition)

Recommendation

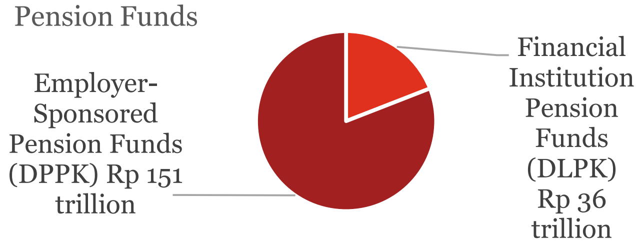
Pension and other funds should be encouraged to channel equity into listed infrastructure products (1)

Government should develop a systematic strategy for channeling a portion of available local capital into domestic infrastructure projects

Other measures to provide equity to IPP projects could be sought. President Jokowi recently announced that he wanted to promote investment from Indonesia's pension funds into infrastructure projects, including power projects[32]. The President believes infrastructure projects will reduce risk and raise returns compared to investing in long-term deposits or Government bonds.

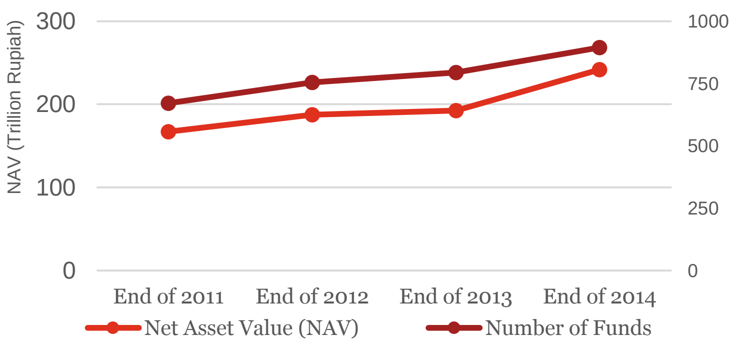
This idea should be further explored and developed. Indonesia's financial markets are not as 'deep' (i.e. large, liquid and offering diverse products) as many of its neighbors, and infrastructure funding is no exception[33].

Figure 32: Pension Funds



Source: Jakarta Post, 2015

Figure 33: Combined Net Asset Value ("NAV") of Mutual Funds in Indonesia



Source: Global Business Guide Indonesia

[32] Source: http://en.tempo.co/read/news/2015/09/03/0566-97467/ BPJS-to-Invest-Pension-Fund-AUM-in-Bonds

[33] Source: www.oliverwyman.com/content/dam/oliver-wyman/global/en/2015/sep/Financial_Deepening_In_Indonesia.pdf

Recommendation

Pension and other funds should be encouraged to channel equity into listed infrastructure products (2)

"Indonesia needs the long-term domestic resources that can be mobilized by Non-Bank Financial Institutions; these can be used to finance productive investments – including, among others, infrastructure"

World Bank, Unlocking Indonesia's domestic financial resources,

In 2014, Indonesia had Rp 187 trillion ($13.8 billion) of pension funds under management and Rp 240 trillion of mutual funds ($17.7 billion)[34]. But, there remains a very limited number of dedicated infrastructure funds. BPJS in 2015 was allowed to diversify its choice of asset classes, but we have not yet seen direct or indirect BPJS participation in infrastructure projects.

In many countries, long-term institutional investors such as insurance companies and pension funds have provided lower-cost equity capital (relative to Private Equity or Infrastructure Funds) to operational infrastructure projects. Having large pools of domestic capital earning a return from domestic infrastructure projects is likely to increase confidence of foreign investors to co-invest too.

Listed companies into which individual projects could divest shares could help funds spread individual project risks. For example, Thailand in 2013 introduced listed infrastructure funds. These were closed-ended with a minimum size of only 500 million Baht ($16 million at the time) for power projects. If greenfield projects comprised up to 30% of total assets, then the fund had to be listed on the Stock Exchange[35]. If more than 30%, the fund would have to list when the projects were developed and could generate income within three years.

At the same time, infrastructure assets provide greater flexibility for fund managers to match risk and return across the portfolio. Infrastructure as an asset class usually provides inflation-protected, stable cash flows.

Clearly the ultimate solution depends on precise returns available and clear evaluation of project risks. Careful consideration of the costs and benefits of divestment, listing and infrastructure funding policy will be required.

Recent steps in this direction are encouraging. For example, the Financial Services Authority recently committed endorsing financial services firms to invest over Rp 1 trillion ($72 million) in the new and renewable energy sector via a limited participation mutual fund[36].

[34] Source: http://www.thejakartapost.com/news/2015/03-/12/ri-pension-fund-growth-slow-still-remains-solid.html

[35] Source: http://www.oliverwyman.com/content/da-m/oliverwyman/global/en/2015/sep/Financial_Deepeni ng_In_Indonesia.pdf

[36] Source: http://www.thejakartapost.com/news/2016/02/0-4/eco-nomy-brief-new-push-renewable-energy-investment.html

07

Appendix 1: Overview of Coal Mining in Indonesia

Regulatory Framework: Coal Mining

Pre-2009: Contracts of Work

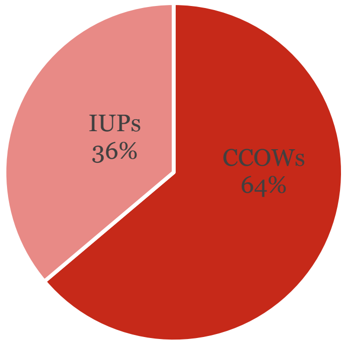
Prior to the issuance of the 2009 Mining Law[37] (Law on Mineral and Coal Mining No. 4/2009), mining operations were either conducted under a Contract of Work ("CoW") with the Government, initially designed for investment by foreign investors, or a *Kuasa Pertambangan* ("KP") i.e. a mining right, exclusively for domestic Indonesian investors.

The CoW system which was introduced in 1967 was gradually refined and modernized over the next 40 years to reflect changing conditions in Indonesia and overseas. There were eventually seven generations of CoWs issued, and three generations of Coal Cooperation Agreements or Coal Contract of Works ("CCoW"), specifically for coal mining. While the CoW/CCoW system was initially envisioned to provide the necessary certainty for foreign investors to make a long-term commitment, some generations of contracts included mandatory requirements to divest to local shareholders, including the first generation CCoWs which required foreign investors to divest down to less than 50% ownership. These first generation CCoWs still produce the majority of Indonesia's thermal coal, and are now in majority Indonesian hands.

Under the CCoW, the mining company acts as a contractor to the Indonesian Government represented by the MoEMR. The coal contractor is entitled to an 86.5% share of the coal produced from the area, and the contractor bears all costs of mine exploration, development and production. The contractors pay the Government's share of production in cash, which represents 13.5% of sales after deduction of selling expense.

The first generation CCoWs are *lex specialis* in terms of law, and continue to bear a corporate income tax rate of 45% (compared to Indonesia's current prevailing rate of 25%), in addition to the 13.5% Government share of production. The first generation CCoWs, however, do also include certain fiscal incentives not generally available under prevailing regulations. KPs, on the other hand, were subject to prevailing tax regulations, and a coal royalty of 3-7% depending on coal quality.

Figure 34: Production in 2014



Source: MoEMR Data, 2015

Since 2009, contractual-based concessions are no longer available for new mining projects. Both the CoW/CCoW framework for foreign investors and the KP framework for Indonesian investors, were replaced by a single area-based licensing system based on specified mining areas.

Existing CoWs/CCoWs will be honoured until their expiry date and may be extended without the need for a tender (if further extensions are still available under the contract). However, implementing regulations for the 2009 Mining Law make it clear that any extension will be in the form of a license under the new system, rather than in the form of a contract.

Post-2009: Mining Licenses

Since 2009, three categories of mining license are available, depending upon the location and nature of the mineral resources:

- *Izin Usaha Pertambangan* (*"IUP"* or Mining Business License);
- *Izin Usaha Pertambangan Khusus* (*"IUPK"* or Special Mining Business License); and
- *Izin Pertambangan Rakyat* (*"IPR"* or People's Mining License).

The majority of production is from CCoWs and as of 2014 the share from those was 64% of total coal production in Indonesia and from IUPs around 36% (see Figure 34).

[37] Law on Mineral and Coal Mining No. 4/2009, 12 January 2009

Regulatory Framework: Coal Mining

The Mining Law

Mineral and coal mining activities are governed under the Law on Mineral and Coal Mining No.4/2009 dated 12 January 2009 (the "Mining Law"). This Law replaces the previous Mining Law No. 11/1967, which provided the framework for all of Indonesia's pre-2009 mining concessions, including all of the existing CoWs and CCoWs.

The Mining Law relies heavily on various implementing regulations including (in order of legal force) Government Regulations, MoEMR Regulations and Directorate General of Mineral and Coal ("DGoMC") Circulars. Figure 35 sets out the most important of these specific to coal.

Figure 35: Coal Mining Regulation

Mining Law
Law No. 4/2009

Ministerial Regulations

DMO PerMen 34/2009 31 Dec 2009	**Benchmark Pricing PerMen 17/2010** 23 Sept 2010	**IUP Tender Procedures PerMen 28/2013** 13 Sept 2013	**Mine Mouth Power Plants PerMen 10/2014** 7 April 2014	**Power Purchasing Price from Coal Mine-Mouth and Non Mine-Mouth Power Plants MoEMR Regulation No. 3/ 2015** 13 January 2015

DGoMC Circulars

Royalty Calculations 32.E/35/DJB/2009	**DMO Credits** 5055/30/DJB/2010	**Coal Benchmark Price:** No. 515.K/32/DJB/2011 & No. 644.K/30/DJB/2013	**Coal Benchmark Price for Mine-Mouth Power Plant:** No. 579.K/32/DJB/2015
Coal Benchmark Price for Certain Types and Uses No. 480.K/30/DJB/2014	**Procedures and Requirement for issuing Recommendation for Registered Coal Exporter:** No. 714.KI/30/DJB/2014		

Domestic Market Obligation

The Central Government has the authority to control production and export of each mining product. The implementing regulations which support the Mining Law also set up the framework for determining the annual DMO for producers, as the Indonesian Government seeks to ensure a sufficient supply of natural resources to meet the expected growth in domestic demand.

The regulations do not set a specific percentage of production to be supplied to the domestic market. Rather, the decision for each particular year is to be made by the MoEMR based on the forecast of domestic demand for the following year. The 2015 DMO was 92.3 million tonnes, compared to actual domestic consumption of 96.6 million tonnes.

The DMO for coal, allocated to each industry group, is outlined in the table below. **As can be seen, growth in domestic coal consumption from 2016 to 2019 is projected by the Government to be 42%.**

Figure 36: DMO 2016 and 2019 (planned)

Industry	2016 quantity (thousand tonnes)	2019 quantity (thousand tonnes) [38]
Coal-Fired Power Plants	86,000	119,000
Metallurgy	4,648	4,648
Fertilizer	1,980	11,075
Cement	10,882	13,215
Textiles	2,390	3,020
Pulp and paper	700	880
Briquettes	30	30
Total	**106,631**	**151,868**
% of Total production [39]	**25%**	**38%**

Source: MoEMR, 2015

[38] Estimated based on MoEMR Presentation, "Pembahasan Penyediaan Batubara untuk Kebutuhan PLTU"

[39] Estimated based on RPJMN & PwC's analysis

Coal Price based on Regulation

Coal in Indonesia

Coal in Indonesia is sold both for domestic and export consumption. Domestic consumption in Indonesia is regulated to meet the DMO requirement, which includes industries such as power plants, cement, smelters, etc (see previous page).

The broad pricing mechanism for Indonesian coal is as follows:

1. Export and domestic purchase (non-coal mine mouth power plant and other industries): based on HBA
2. Domestic (CMM power plant): using production cost plus 25% margin as set out in MoEMR Regulation No. 10/2014.

1. Coal price benchmarking under HBA/HPB

In September 2010, the MoEMR issued Ministerial Regulation No. 17/2010 on the Procedure for the Setting of Benchmark Prices For Mineral and Coal Sales, which stipulates that the sale of coal shall be conducted with reference to the benchmark price issued by the Government.

The benchmark prices for thermal coal use a formula that refers to the average coal prices based on local and international market indexes. The Government determines the HBA that is then used for coal on a monthly basis.

For thermal coal (commonly used for CFPP and steam boilers), the HBA was set by averaging four coal price indices: Indonesia Coal Index ("ICI"), Platts, Newcastle Export Index ("NEX") and New Castle Global Coal Index ("GC") for the previous month. Each have an equal contribution (25%) to the reference price. However, in January 2016 the MoEMR has announced a revision to the formula for HBA.

The Platts index will no longer be included and the weighting for ICI will be revised to 50%.

The formula for the HBA is as shown below:

HBA = 50% ICI1 + 25% NEX + 25% GC

Categories are divided based on coal quality, with the base HBA quality set at 6,322 kcal/kg (As Received Basis or "arb"), total moisture ("TM") content of 8% (arb), sulphur content of 0.8% (arb), and ash content of 15% (arb).

The HBA is then used to determine a Coal Benchmark Price known as *Harga Patokan Batubara ("HPB")*, that follows HBA plus adjustments for coal characteristics (sulphur, ash, moisture). The Benchmark price is quoted as the Free on Board ("FOB") price at the point of sale.

Accordingly, certain costs are accepted to adjust the price if the delivery takes place at a point other than the FOB vessel (e.g., FOB barge or Cost Insurance Freight ("CIF")). The allowable adjustments would include the costs of barging, surveyors, insurance and transshipment.

The HPB serves as a "floor price" for the Government royalty calculation. If the actual sales price is higher than the HPB, the royalty will be based on actual sales price. However, if the actual sales price is lower than HPB, the royalty should be calculated based on HPB.

The benchmark price (HPB) is applicable for spot sales and long-term sales. For long-term sales, PerMen 17 requires mining companies to adjust the sales price every 12 months. Specifically for coal, the long-term coal sales price is determined based on the weighted coal benchmark price for the preceding three months. A coal mining company is required to notify the DGoMC of the proposed sales price before signing a long-term sales agreement.

Coal Price based on Regulation

2. Coal price benchmarking for CMM power plants

For coal intended for use in CMM power plants, MoEMR Regulation No.10/2014 (“PerMen 10”) sets out fixed prices based on benchmark costs and provided inputs such as expected stripping ratio.

The basic coal price is to be the production cost (determined by the DGoMC) plus 25% margin regardless of the calorific value of the coal (previously only coal with a calorific value of less than 3,000 kcal/kg was allowed). Once approved by the MoEMR, the basic coal price will be valid for the duration of the Power Purchase Agreement (“PPA”), with a price escalation considered each year based on the exchange rate, diesel prices, the consumer price index and wages.

DGoMC Regulation No. 953.K/32/DJB/2015 provides the latest prices for CMM power plant coal, and is reproduced below.

Figure 37: Regulated Production Costs of the Coal Mining System

Items	Primary Unit	Unit Cost
Direct Production Costs		
Overburden Removal	$/ bcm	2.17 – 2.41
Overburden transport	$/ tonne/ km	0.87 – 1.74
Coal extraction	$/ tonne	1.55 – 1.70
Coal transportation from mine to processing facility	$/ tonne/ km	0.20 – 0.28
Coal transportation from processing facility to stockpile of power plant	$/ tonne/km	Agreement between coal miners with IUPTL holders
Indirect Production Costs		
Coal processing	$/ tonne	1.19 – 1.98
Amortization and depreciation	$/ tonne	5.50 – 6.88
General Costs and Administration		
Monitoring and environmental management, health and safety of workers, community development	$/ tonne	0.50 – 0.55
Overheads	$/ tonne	1.66 – 2.07
Dead rents	$/ tonne	0.10 – 0.11
Production fee/royalty assumption	$/ tonne	20.3%
Margin	$/ tonne	25%

Source: DGoMC Circular Letter No. 953.K/32/DJ/2015

Appendix 2: Overview of Power Sector in Indonesia

Power Framework

Introduction

Power in Indonesia is generated by both PLN and private sector IPPs. Transmission and Distribution ("T&D") is not restricted to PLN in law, although currently PLN is the only owner and operator of T&D assets.

Electricity planning

MoEMR is the government body in charge of developing the General Plan of Electricity ("RUKN"). The plan consists of policies relating to investment, funding, and strategy on renewable energy. PLN with approval from MoEMR also publishes its Electrical Power Supply Business Plan ("RUPTL") that consists of a 10 year electricity development plan. The RUPTL consists demand forecasts, future expansion plans, electricity production, and other relevant information in the provision of electricity in Indonesia.

Electricity regulation

Electricity Law No. 30/2009 provides the regulatory framework that guides the provision of electricity in Indonesia. The regulation covers these topics:

a) Commercial structure: including licensing, electricity business, utilization of the fuel mix, and supply and demand.
b) Land acquisition: including financial transactions on the land that will be used in the provision of electricity.
c) Tariffs: including tariff-setting mechanism.
d) Environmental and health and safety: including health and safety procedures and environmental awareness
e) Other points including: maintenance and supervision, sanctions, and investigation.

PLN and IPPs

The power generation sector is dominated by PLN which controls around 70% of generating assets in Indonesia[40] including through subsidiaries such as Indonesia Power, Pembangkit Jawa Bali, PLN Batam and PLN Tarakan.

Private sector participation is allowed through IPPs and own use-captive power. IPP appointment is most often through open tender although they can be directly selected or directly appointed in certain circumstances. In line with Government Regulation No.14/2012 as amended by No.23/2014, MoEMR Regulation No.3/2015 states that PLN may purchase power using the direct selection and direct appointment method for CMM power plants with a capacity greater than 10 MW.

Electricity business license for public use ("IUPTLs") can be offered to IPPs with up to 95% foreign shareholding when generating more than 10 MW of electricity. However, this is increased to 100% foreign shareholding if constituting a PPP project.

Electricity Law No. 30/2009 and Government Regulation No. 14/2012 state that private sector participation is (in effect) limited to power generation.

The 2009 Electricity Law provides PLN with priority rights to conduct its business throughout Indonesia. As the sole owner of T&D assets, PLN is 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 T&D, currently private sector participation is in effect still limited to the power generation sector.

[40] Source: Renstra KESDM 2015-2019

Power Regulatory Framework

Purchasing power from CFPPs

Power purchase procedures and benchmark prices in PPAs from IPPs to PLN are regulated under MoEMR Regulation No.3/2015 for CMM and Non-CMM power plants (with a capacity greater than 10 MW).

The power tariff is based on the Levelized base price and price applicable on the Commercial Operations Date ("COD") of the plant. Note that these are 'maximum benchmark' prices. Actual prices may be both higher (with Ministerial Approval) and also lower.

The pricing structure is shown in Figure 38.

The mine owners who supply CMM power plants must have their concessions listed on the Clean-and-Clear List and must have the reserve allocation and coal quality required by the power plant. It is also required that the mine owner owns a minimum of 10% of the shares of the power plant company. This requirement is designed to help secure the supply of coal for CMM projects.

Figure 38: Purchasing Price Power from CMM and Non-CMM Power Plants, based on Assumptions Outlined in the Regulation

Capacity Unit (MW)	Power Plants	50	100	150	300	600	1,000
Price ($ cents / kWh)	CMM		8.21	7.65	7.19	6.90	
	Non-CMM	9.11	8.43	7.84	7.25	6.96	6.31
Availability Factor	CMM & Non-CMM	80%					
Contract Period	CMM	30 years from COD					
	Non- CMM	25 years from COD					
Heat Rate (kcal/kWh)	CMM		3,200	3,000	2,900	2,700	
	Non- CMM	3,200	3,000	2,800	2,600	2,450	2,290
Calorific Value (GAR) kcal/kg	CMM	3,000					
	Non- CMM	5,000					
Coal Price $ / metric ton (CIF)	CMM	30					
	Non- CMM	60					

Source: MoEMR Regulation No. 3/ 2015

Electricity Tariff

Levelized cost of electricity

Different technologies incur significantly different generation costs. Levelized cost of electricity ("LCoE") is often used as summary measure of the overall cost to build and operate a plant using a specific technology over its lifetime. The cost is typically set per-kilowatt-hour.

Under PLN's procurement guideline, key inputs to calculating LCoE paid to IPPs comprise the following components:

- Component A: Capital Cost Recovery Charge Rate
- Component B: Fixed Operation and Maintenance Cost Recovery Charge Rate
- Component C: Energy Charge Rate, or fuel cost
- Component D: Variable Operation and Maintenance Cost Recovery Charge Rate
- Component E: Transmission Cost. Capital cost recovery charge rate for the transmission line

Electrical power price

The price at which PLN sells power to end users is party regulated; PLN proposes tariffs but the MoEMR must approve them.

PLN has generally required a Ministry of Finance subsidy to break even. For example, in 2013 PLN made a net loss of Rp 102/kWh and in 2014 of Rp 38/kWh[41]. On average between 2010 and 2014, cost exceeded revenue per kWh by 15%.

Over the past few years, the Government of Indonesia has increased electricity tariffs for several tariff groups and since MoEMR Regulation No.9/2015 some tariffs have moved in line with the $/Rp exchange rate, inflation and the Indonesian Crude Price.

As a rule of thumb therefore, losses borne by PLN will be passed through to the Ministry of Finance.

Figure 39: Key Electricity Tariffs (February 2016)

Tariff Group		Power	Rp/kWh	$/kWh
Small Household	R-1/TR	450 VA	360	0.03
	R-1/TR	900VA	360	0.03
	R-1/TR	1,300 VA	1,392	0.10
	R-1/TR	2,200 VA	1,392	0.10
Medium-Household	R-2/TR	3,500 VA - 5,500 VA	1,392	0.10
Large-Household	R-3/TR	6,600 VA – 200 kVA	1,392	0.10
Medium-Business	B-2/TR	6,600 VA – 200 kVa	1,392	0.10
Large-Business	B-3/TM	> 200 kVA	1,071	0.08
Medium-Industry	I-3/TM	> 200 kVA	1,071	0.08
Large-Industry	I-4/TT	> 30,000 kVA	959	0.07
Medium-Government Office	P-1/TR	6,600 VA – 200 kVA	2,392	0.18
Large-Government Office	P-2/TM	> 200 kVA	1,071	0.08
Street Lighting	P-3/TR		1,392	0.10
Special services	L/TR, TM, TT		1,573	0.12

Source: PLN's Tariff Adjustment List (February 2016)

[41] Source: PLN RUPTL 2015-2024 (from Pacific Rim Information Memorandum)

Survey of APBI members: Questions (1)

1. What is the location of your company's mining concessions?

*(Dimana letak konsensi pertambangan Anda?)**

- Location 1 : (choose between Lampung, South Sumatera, West Kalimantan, East Kalimantan, Central Kalimantan, South Kalimantan, North Kalimantan, Papua, Others, None)
- Location 2 : (choose between Lampung, South Sumatera, West Kalimantan, East Kalimantan, Central Kalimantan, South Kalimantan, North Kalimantan, Papua, Others, None)
- Location 3 : (choose between Lampung, South Sumatera, West Kalimantan, East Kalimantan, Central Kalimantan, South Kalimantan, North Kalimantan, Papua, Others, None)
- Location 4 : (choose between Lampung, South Sumatera, West Kalimantan, East Kalimantan, Central Kalimantan, South Kalimantan, North Kalimantan, Papua, Others, None)
- Location 5 : (choose between Lampung, South Sumatera, West Kalimantan, East Kalimantan, Central Kalimantan, South Kalimantan, North Kalimantan, Papua, Others, None)
- Location 6 : (choose between Lampung, South Sumatera, West Kalimantan, East Kalimantan, Central Kalimantan, South Kalimantan, North Kalimantan, Papua, Others, None)

2. In which coal mining stage is your company?

*(Dalam tahap kegiatan pertambangan apakah Perusahaan Anda berada?)**

- Prospection (Prospeksi)
- Exploration (Eksplorasi)
- Production (Produksi)
- Other

3. What was your company's production and sales volume in 2015?

*(Berapa jumlah volume produksi & penjualan Perusahaan Anda selama 2015?)**

- <1 million tonne
- 1 - <2 million tonne
- 2 - <5 million tonne
- 5 - <10 million tonne
- 10 million tonne or more

Survey of APBI members: Questions (2)

4. What is the projected amount of change in the volume of production and sales of your company in 2016 as compared to 2015?

(Berapa perubahan volume produksi & penjualan Perusahaan Anda pada tahun 2016 dibandingkan tahun 2015 ini?)*

• Delayed/not producing

• Decrease <25%

• Decrease 25%-<50%

• Decrease 50%-<75%

• Decrease by 75% or more

• Stable

• Increase <25%

• Increase 25%-<50%

• Increase 50%-<75%

• Increase 75% or more

• Other

5. What is the level of reduction in your company's reserves from the last JORC measurement until now, based on the current price of coal?

*(Berapa jumlah berkurangnya cadangan batubara (reserves) Perusahaan Anda dari terakhir melakukan pengukuran JORC hingga saat ini, berdasarkan harga batubara saat ini?)**

• Decrease <10%

• Decrease 10%-<20%

• Decrease 20%-<30%

• Decrease 30%-<40%

• Decrease 40%-<50%

• Decrease 50%-<60%

• Decrease 60%-<70%

• Decrease 80%-<90%

• Decrease 90%-<100%

• Other

Survey of APBI members: Questions (3)

6. Out of the total volume of your company's coal sales in 2015, what is the portion (in percentage terms) of the domestic sales of coal to power plant companies?

(Dari jumlah volume penjualan batubara Perusahaan Anda selama tahun 2015, berapakah porsi (persen) penjualan domestik kepada perusahaan pembangkit listrik? [Dalam %])

7. Out of the total volume of your company's coal sales in 2015, what is the portion (in percentage terms) of the domestic sales of coal to other companies aside from power plant companies?

(Dari jumlah volume penjualan batubara Perusahaan Anda selama tahun 2015, berapakah porsi (persen) penjualan domestic kepada perusahaan-perusahaan selain perusahaan pembangkit listrik? [Dalam %])

8. Out of the total volume of your company's coal sales in 2015, what is the portion (in percentage terms) of export?

(Dari jumlah volume penjualan batubara Perusahaan Anda selama tahun 2015, berapakah porsi (persen) penjualan ekspor? [Dalam %])

9. Out of the total projected volume of your company's coal sales for 2016, what is the portion (in percentage terms) of domestic sales to power plant companies?

(Dari jumlah proyeksi volume penjualan batubara Perusahaan Anda untuk tahun 2016, berapakah porsi (persen) penjualan domestic kepada perusahaan pembangkit listrik? [Dalam %])

10. Out of the total projected volume of your company's coal sales for 2016, what is the portion (in percentage terms) of domestic sales to other companies aside from power plant companies?

(Dari jumlah proyeksi volume penjualan batubara Perusahaan Anda untuk tahun 2016, berapakah porsi (persen) penjualan domestic kepada perusahaan-perusahaan selain perusahaan pembangkit listrik? [Dalam %])

11. Out of the total projected volume of your company's coal sales for 2016, what is the portion (in percentage terms) of export?

(Dari jumlah proyeksi volume penjualan batubara Perusahaan Anda untuk tahun 2016, berapakah porsi (persen) penjualan ekspor? [Dalam %])

Survey of APBI members: Questions (4)

12. What was your company's Capex in 2015? [in million $]

*(Berapa Capex perusahaan Anda pada tahun 2015? [Dalam juta $]**

• $0 - <5 million

• $5 - <10 million

• $10 – <15 million

• $15 - <20 million

• $20 -<25 million

• $25 - <30 million

• $30 million or more

13. What is the projected change in your company's Capex in 2016 as compared to 2015?

(Berapa proyeksi perubahan Capex perusahaan Anda pada tahun 2016 dibandingkan tahun 2015?)*

• Decrease <25%

• Decrease 25% - <50%

• Decrease 50% or more

• Stable

• Increase <25%

• Increase 25% - <50%

• Increase 50% or more

• Other

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