Overpaid and Underutilized:

How Capacity Payments to Coal-Fired Power Plants Could Lock Indonesia into a High-Cost Electricity Future

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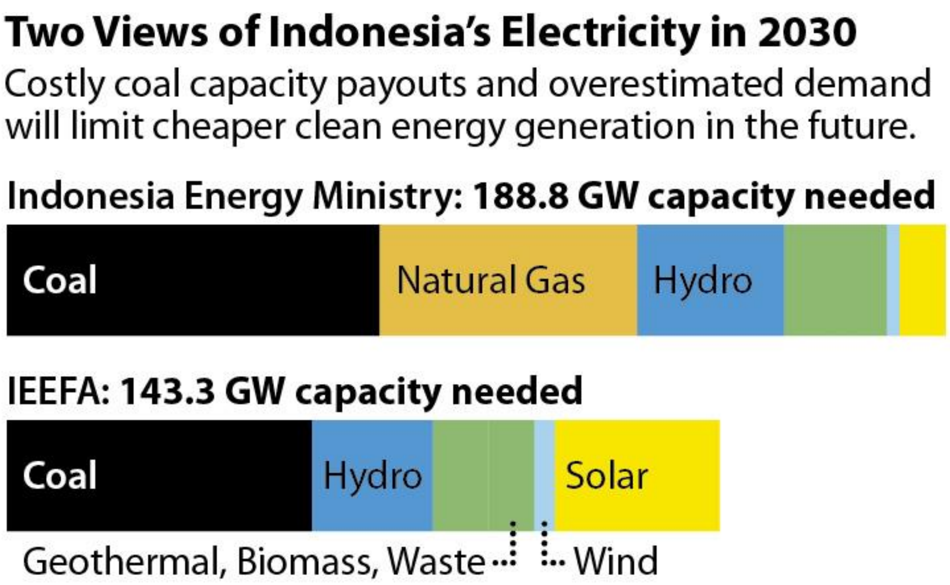
Executive Summary

Capacity payments have been instrumental in promoting private investment in the Indonesian power sector. The practice provides independent power producers (IPPs) an assured revenue stream that covers an adequate return on the significant project capital investment and risks to which they are exposed.

However capacity payments also expose the Indonesian utility, Perusahaan Listrik Negara (PLN), and Indonesian consumers, to significant risk of paying for power that is not needed.

Capacity payments are part of the tariff calculated based on the power capacity of a plant, regardless of whether the power produced by the plant is dispatched, paid by the offtaker for each kilowatt of available capacity.

As renewable energy costs have come down drastically, renewables are forcing utilities, policymakers and regulators around the world to rethink the way the electricity sector is structured. Further commitments to coal-fired power plants will require PLN to make significant financial outlays, saddling the utility with costly 25-year power purchase agreements and payment for potentially un-needed power from underutilized plants.



Key Findings

1. IEEFA estimates that PLN contracts to pay approximately US$3.16 billion per gigawatt of installed capacity in the form of capacity payment for power availability from coal-fired plants. According to PLN's 2017-2026 Electricity Supply Business Plan (RUPTL), a total of 24GW of coal-fired power and mine-mouth power generation capacity has been allocated to IPPs. In aggregate, PLN will pay an estimated US$76 billion over the course of 25-year PPAs to secure access to this scheduled capacity. As renewable sources such as wind and solar become cheaper and contribute a greater proportion of the overall energy mix through priority dispatch, PLN will face the unwelcome prospect of having to continue

to make capacity payments to thermal power IPPs even though less power will be sourced from them. In effect, capacity payments disincentivize PLN from procuring more renewable energy as a way of avoiding paying future capacity charges for underutilized thermal plants.

2. The Java-Bali system requires a reserve margin of 25% in accordance with PLN's planning. Progressing with the capacity increase from all energy sources for Java-Bali will increase the reserve margin to more than 40%, reaching 55% in 2019. The proportion of coal-fired power generation capacity assigned to IPP from 2017 to 2026 is 12,845MW. Assuming 40% of this capacity will remain un-dispatched, considering the current utilization rate of 57%, this would amount to 5,138MW, translating into an obligation to pay US$16.2 billion for idle capacity. Even without a single IPP coal-fired power plant capacity contract being added to Java-Bali from 2017 to 2026, the reserve margin will still be at or above 12% throughout this period, and will be at 16% in 2026 for this individual power network, where 80% of demand resides.
3. The cost of coal power is inflationary, as both fixed and variable operation and maintenance costs are indexed to the inflation rate. This truth is borne out by comparing the cost of power generation (BPP) in Indonesia between 2015 and 2016. A total of 16 of 21 provinces have seen their regional BPP increase, due to dominance of thermal power generation. On the other hand, the cost of renewable is falling rapidly. The levelized cost of electricity (LCOE) for solar in Indonesia is estimated at USD 17 cents/kWh in 2016. We see solar PV becoming grid competitive at around USD 8 cents/kWh in 2021, and even Java and Bali, where there is low BPP, will benefit from cheaper renewable prices soon after that. This analysis ignores the additional cost externalities of thermal power generation, suggesting that a fully costed grid parity comparison will be achieved well before 2020.

This report acknowledges the importance of continuing the use of capacity payments to encourage private sector investment in Indonesia. However, the more entrenched these commitments are and the farther they stretch into the future, the likelier they will serve the interest of aging and under-utilized thermal power plants at the expense of better investments.

An economical alternative to national energy security exists through the development of renewable energy and the diversification of energy sources in Indonsia's power generation portfolio.

Introduction

Indonesia's economic growth, rising living standards, urbanization and population growth set the stage for significant increases in electricity demand. The utility Perusahaan Listrik Negara (PLN), which has a monopoly on electricity distribution and is the sole offtaker for all electricity produced in the country, states that the twin goals of power system planning are:

- To achieve security of supply, measured by universal electrification and a healthy reserve margin of 25-30% in Java-Bali and 35-40% in the rest of the country[1] (reserve margin is the difference between capacity and peak demand); and
- To achieve the above goal at the lowest electricity supply cost.

To meet current and future demand, Indonesia needs significant investment in power generation. Forecast power sector investment requirements from 2013 to 2022 total US$124.5 billion, or US$12.5 billion per annum, of which 73% will be for generation. PLN expects to deliver 41% of new generation, transmission and distribution capacity, while 59% (US$54 billion) will depend on participation by independent power producers (IPP).[2]

To encourage private sector investment, PLN offers IPPs security of future revenue through power purchase agreements (PPAs). A key characteristic of a PPA is that the offtaker absorbs all market risk. PLN is responsible for developing an estimate of long-term power demand. If the demand does not meet expectations, PLN is still obligated to pay for the contracted amount under the PPA's take-or-pay provisions. This payment component is called a capacity payment, or capacity charge.

Capacity payment is made to the IPP as long as the power capacity is available, and regardless of whether the power generated is needed, or dispatched. In return, PLN is guaranteed long term output from the project.

This report analyses the risk of overpaying for electricity under the regime of PPAs, which guarantee capacity payments for coal-fired power generation. Such overpayments stand to defeat efforts to achieve energy security at the lowest cost possible.

IEEFA offers an alternative strategy to provide for the country's future energy needs.

Definition of Capacity Payment

Under PLN's procurement guidelines, PPAs signed between PLN and IPPs of thermal power plants are for fixed terms of approximately 25 years, or for a maximum of 30 years after Commercial Operation Date (COD). Capacity payment, as part of the tariff, is a fixed payment calculated based on the installed capacity of the power plant with specific availability factor agreed to by an IPP and PLN. It is paid for each kilowatt of available (not necessarily dispatched) capacity. Specifically, it covers:[3]

[1] PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).
[2] International Energy Agency. (2015). Indonesia 2015. https://www.iea.org/publications/freepublications/publication/Indonesia_IDR.pdf
[3] PLN. (2017). General Terms in IPP Business Plan. http://www.pln.co.id/wp-content/uploads/2011/03/Buku-IPP.pdf

I. Repayment of the principal and interest of the debt used to construct the power plant, usually on a non-recourse basis;

II. Return on equity invested by project sponsors; and

III. Fixed operation and maintenance (O&M) costs that are independent of the amount of energy generated (e.g., staffing costs, administrative expenses, operator fee, insurance premiums, etc.).

The first two components are paid to IPPs as part of capital recovery charges.

Variable components of the tariffs, based on power dispatched, contain:

I. Energy Charge Rate, or fuel cost, which is usually a pass-through cost in that PLN bears it;

II. Variable O&M Cost Recovery Charge Rate.

Capacity payments usually make up 30% to 40% of the total tariff.

The proportion of additional coal-fired and mine-mouth power generation capacity allocated to IPPs is planned to reach 24,082MW between 2017 and 2026, excluding capacity that is as yet unallocated.[4] In total, PLN controls around 70% of current generating assets in Indonesia.[5]

Benchmark prices in PPAs are based on the levelized base price and price applicable on the COD of the plant. The Ministry of Energy and Mineral Resources (MEMR) has stated a reference price for different types of coal-fired power plants in Regulation 19/2017. In the case of mine-mouth power plants, the decree dictates that if the cost to supply electricity (BPP) in a region is higher than the national average, the electricity tariff will be capped at 75% of average national rates. If the BPP in a region is lower or equal to the national average, then the electricity tariffs should be capped at 75% of the region's average.

For regular coal-fired power plants with capacity under 100MW, if the BPP is lower than the national average, tariffs must not exceed the local BPP. If the BPP is higher than the national average, electricity tariffs must not be higher than the national BPP.

Based on bids won in recent years, actual tariff paid to IPPs ranged between USD 7 -10 cents/kWh.

Most intermittent renewable energy IPP projects such as solar and wind do not have capacity charges. Their tariff is based on a single-tariff scheme.[6]

[4] PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).

[5] PwC. (March 2016). Supplying and Financing Coal-Fired Power Plants in the 35GW Programme. http://www.apbi-icma.org/wp-content/uploads/2016/03/03-03-2016-APBI-PwC-Report-on-Supplying-and-Financing-the-35-GW-program-FINAL-FINAL-rev-8-32016.pdf

[6] PLN. (2017). General Terms in IPP Business Plan. http://www.pln.co.id/wp-content/uploads/2011/03/Buku-IPP.pdf

Changes to Take-or-Pay Commitments in Power Purchase Agreements

PPA models used in Indonesia commit PLN to take-or-pay clauses for the entire life of the PPA, which has a maximum duration of 30 years. This strategy has been instrumental in attracting private sector investment, providing IPPs an assured revenue stream that covers an adequate return on the significant project capital investment and risks to which they are exposed.

It is also a form of contract that is generally understood by lenders, and it is often the most important means for IPPs to secure external debt financing on a non-recourse or limited recourse basis.

In January 2017, the Ministry of Energy and Mineral Resources issued Regulation No. 10/2017 on Principles of Power Purchase Agreements (Reg. 10). One aspect of Reg. 10 states that the take-or-pay timeframe within a PPA is for a "certain period," which could be interpreted as a duration for less than the full term of the PPA, perhaps for only the debt-servicing period. Lenders are assured that the bankability of the project will remain the same, whilst IPPs will have to take the risk on whether PLN will dispatch from their plants after the debt is repaid.

This change, yet to be definitively applied, will be subject to negotiation between IPPs and PLN. But it could transfer the risk of bearing a residual stranded asset from PLN to investors if it is interpreted narrowly by PLN.

According to the International Energy Agency, stranded assets are "investments which have already been made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment brought about by climate policy."[7] This definition might, for example, include power plants that are retired early, or are underutilized because of the availability of cheaper renewable energy. Without capacity payment, IPPs will bear such stranded asset risk if their plants operate less than expected, and generate less revenue than forecast.

If PLN opts to shorten the capacity payment period, it would reduce its contracted financial cost for un-dispatched power, and the associated stranded asset risk, as it is not obliged to pay power developers after the debt period. A 20-year tenor loan will cover approximately 16 years of a 25-year PPA (assuming a four-year construction period).

The Indonesian government has taken steps to improve investor confidence and bankability of power projects. Since 2015, Badan Koordinasi Penanaman Modal (BKPM) has offered private investors one-stop services to swiftly and systematically obtain licensing approval. The government has also made concrete steps to reform the electricity tariff and reduce the level of subsidies, bringing tariffs closer to recovering cost of power generation. Any reduction in financing cost, supported by Indonesia's sovereign ratings upgrade in May 2017, would further improve investor sentiment to the extent that capacity charge would not necessarily need to cover the whole duration of the PPA in order for projects to be bankable. Also, as the capacity

[7] IEA. (2013). Redrawing the Energy-Climate Map. World Energy Outlook Special Report. http://www.iea.org/publications/freepublications/publication/WEO_Special_Report_2013_Redrawing_the_Energy_Climate_Map.pdf

charge would cover the debt servicing period, lenders would still be assured of the borrowers/IPPs' ability to repay the loan.

Implications of Using Capacity Payment

This section outlines the implications to PLN and the Indonesian government of using capacity charge to further power sector development. It explains the risk of overpaying for electricity when more economical renewable energy becomes available.

Financial Outlay to Secure Power Availability Will Amount to as Much as US$76 Billion

We estimate that PLN pays US$3.16 billion/GW in the form of capacity payment for a coal-fired power plant. This is based on a debt tenor of 20 years with an all-in interest of 5%, a PPA of 25 years and targeted equity return of 12%. See the parameters in Table 1.

Table 1: Parameters

Project costs	US$/MW	2,000,000
Fixed O&M	US$/MW/y	50,000
US Consumer Price Index	%	2.20%
Indonesia Consumer Price Index	%	4.30%
Discount rate (based on gov. bond coupon)	%	5%
Gearing ratio (debt to equity)	%	80%
Debt amount	US$/MW	1,600,000
Equity amount	US$/MW	400,000
All-in interest rate	%	5%
Target equity return	%	12%
Construction tenor	years	4
Debt tenor	years	20
Capacity payment tenor	years	25
PPA tenor	years	25

Estimated capacity charge per GW

Total Capacity charge to PLN	USD MM/GW	3,157
Fixed Operation & Maintenance	USD MM/GW	929
Capital Cost Recovery Charge	USD MM/GW	2,228

According to RUPTL 2017-2026, a total of 24GW of coal fired power (PLTU) and mine-mouth power (PLTU MT) generation capacity has been allocated to IPPs,[8] which will receive the capacity payment. See Table 2. On this basis, in aggregate, PLN will pay US$76 billion to have access to all the capacity scheduled.

Table 2

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
PLTU	MW	781	425	8534	2775	621	1300	-	100	-	2200	16736
PLTU MT	MW	28	28	300	1140	2100	1200	1150	800	-	600	7346
												24082

Capacity charges for coal-fired power plants are particularly notable as these plants are far less flexible than gas-fired counterparts in accommodating variable renewable energy input into the grid.

IEEFA projects that Indonesia will need additional production of 286.4 TWh (see Table 3) by 2030. This compares against Draft RUKN 2015-2034's projection that the country will need an additional 575 TWh by 2030, 400 TWh of which, or about 70%, will be generated by IPPs.[9] The amount of generation in excess of IEEFA's projection is 288.6 TWh—a massive over-estimation of likely demand growth that will have very significant cost implications for PLN and hence consumers.

Table 3

			TWh
Net Electricity consumed in Indonesia in 2015			211.8
Real GDP Growth	5.5%	Per annum	
Electricity to GDP multiplier	1.16	times	
Electricity Demand Growth	6.4%	Per annum	
Energy Efficiency Gains	1.0%	Per annum	
Growth in gross production AT&C losses			
Reduced grid AT&C losses	-0.2%	Per annum grid efficiency gain	
Net Electricity consumed in Indonesia in 2030			470.1
Electricity consumption growth required			258.4
Production growth required			**286.4**

In terms of generation capacity, the IEEFA case projects that a total of 143,315MW of installed capacity will be required by 2030 to meet Indonesia's demand. See Table 4. This projection takes into account a significant but feasible increase in renewable energy to be installed by

[8] PLN. (2017). RUPTL 2017-2026.

[9] MEMR. (November 2015) Power Policy and National Development Plan in Indonesia. http://www.eri.chula.ac.th/eri-main/wp-content/uploads/2015/11/S1-2_Mr._Jarman_MEMR_final_rev.pdf

2030, based on both MEMR's existing renewable commitments and the International Renewable Energy Agency (IRENA) estimate. The MEMR case is based on thermal power projections as outlined in the Indonesia Energy Outlook 2016, and existing MEMR renewable energy commitments.[10] The official commitment of the National Energy Policy (Kebijakan Energi Nasional, KEN) and the National Energy Master Plan (Rencana Umum *Energi* Nasional, RUEN) is 23% of new and renewable energy in the overall energy mix by 2025.

Table 4

Based on Indonesia Energy Outlook 2016 The Increase in Net Electricity Demand is Met by:	Installed Total 2015 (MW)	MEMR case - Installed Total by 2030 (MW)	IEEFA case - Installed Total by 2030 (MW)
Utility scale solar	14	2,400	21,280
Rooftop solar	-	4,800	9,750
Offgrid solar	-	2,100	2,100
Wind	1	2,600	4,200
Biomass and Waste to Energy	124	7,200	9,200
Hydro electricity (large, mycro, mini)	5,262	29,600	24,300
Geothermal	1,439	8,900	8,900
Marine (tidal)	-	4,500	2,250
Natural gas (inclu. Gas PP, Gas engine, CCPP)	16,355	51,726	
Oil and diesel	6,356	-	
Coal (inclu. Coal Steam, Coal gasification)	25,984	74,942	
Total thermal (subtotal)	**48,694**	**126,668**	**61,335**
Total installed capacity	**55,533**	**188,768**	**143,315**

The difference between the MEMR's and IEEFA's projection (188,768MW and 143,315MW respectively) is accounted for by the difference in the extent of electricity sector demand growth over the forecast period (with IEEFA assuming lower economic growth and a greater contribution from energy efficiency savings), while the composition differences reflect different views on the rate to which renewable energy potential is realized, with the residual portion (i.e. the difference between total installed capacity and all renewable sources in the IEEFA case) assigned to thermal power.

Specifically on solar, the IEEFA projection (33GW for utility, rooftop and offgrid solar combined) is more ambitious than MEMR's. IEEFA has referenced both MEMR's solar projection (9.3GW) as well as IRENA's projection (47.2GW), and our projection represents a partial deployment of the amount of available space for ground-mounted and rooftop solar PV and the ability of grids to deal with the supply of variable renewable energy.

[10] International Renewable Energy Agency (IRENA). (March 2017). Renewable energy Prospects Indonesia. The renewable commitments are based on targets set in the National Electricity General Plan (RUKN) and the National Energy Policy (KEN). http://www.irena.org/DocumentDownloads/Publications/IRENA_REmap_Indonesia_report_2017.pdf

Were PLN to stay on course to develop all the planned thermal power, and assuming IPP invests in 50% of this excess capacity, this would amount to a total of 32,667MW. See Table 5. On the basis that PLN will have to pay US$3.16 billion per GW on capacity charge, and assuming that all of the generation will be coal-based as it represents the cheapest form of thermal power (when cost externalities and capital subsidies are both ignored), costs total to US$103 billion for this capacity.

Table 5

	MW
MEMR Projected installed capacity for thermal power	126,668
IEEFA Projected installed capacity for thermal power	61,335
Difference between IEEFA and MEMR	65,333
IPP portion (assuming 50%)	32,667

Source: IRENA,[11] IEEFA analysis, RUPTL 2017-2026, Indonesia Energy Outlook 2016[12]

Java-Bali System Needs Far Less Power Than Planned

For the Java-Bali system, the required reserve margin is approximately 25-30%.[13] According to RUPTL 2017-2026, to progress with all the planned capacity increases for Java-Bali would mean increasing the reserve margin to more than 40%, reaching 55% in 2019. See Table 6.

Table 6

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load Netto	MW	6,646	28,558	30,653	33,330	35,722	38,242	40,906	43,743	46,755	49,919
Total capacity	MW	3,891	5,937	47,580	49,608	51,860	55,016	56,636	61,131	67,740	70,540
Reserve Margin	%	27%	26%	55%	49%	45%	44%	38%	40%	45%	41%

The proportion of coal-fired power generation capacity assigned to IPPs from 2017 to 2026 is 12,845MW[14] in the Java-Bali grid. Even without a single IPP coal-fired power plant capacity being added from 2017 to 2026, the reserve margin is at or above 12% throughout this period, and will be at 16% in 2026 for this individual power network, where 80% of demand resides. See Table 7.

[11] International Renewable Energy Agency (IRENA). (March 2017). Renewable energy Prospects Indonesia. http://www.irena.org/DocumentDownloads/Publications/IRENA_REmap_Indonesia_report_2017.pdf

[12] National Energy Council. (November 2016). Indonesia Energy Outlook. http://den.go.id/index.php/publikasi/index/EnergyOutlook

[13] PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).

[14] Ibid.

Assuming 40% of this capacity will remain undispatched (a reasonable assumption considering the current utilization rate of 57.3%, according to IEEFA's analysis[15]), this amounts to 5,138MW, translating into an obligation to pay US$16.2 billion for idle capacity generated by coal-fired power plants over 25 years.

MEMR has acknowledged that Java will have a 5GW surplus in electricity capacity even with its announcement that it will suspend 9GW worth of projects.[16] PLN's planning for the next RUPTL should reflect this downward revision.

Table 7

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load Netto	MW	26,646	28,558	30,653	33,330	35,722	38,242	40,906	43,743	46,755	49,919
IPP Coal Addition	MW	625	-	7,270	1,950	-	1,000	-	-	-	2,000
Total capacity without IPP coal addition	MW	33,266	35,312	39,685	39,763	42,015	44,171	45,791	50,286	56,895	57,695
Reserve margin	%	25%	24%	29%	19%	18%	16%	12%	15%	22%	16%

Enticing Private Sector Investment Comes at Significant Cost to Indonesia

As the growth of electricity demand outstrips the financial ability of PLN to build adequate capacity, capacity payments become a key feature of PPAs as a way to encourage private investment. This strategy provides PLN a degree of energy security by way of having enough capacity at its disposal to meet demand.

IPPs demand capacity paymenst to recoup their fixed costs and to gain a return on the equity invested. They are wary of rising calls for fairer or lower tariffs, concerned that such action would prohibit investors from achieving their targeted rate of return once they have sunk capital.

To this end, IPP participation has been instrumental in expanding power generation capacity in Indonesia, although this expansion has been accomplished at a significant cost. The PPA with Paiton Energy (which operates a 2,035MW coal-fired power plant) in 1991 has a project

[15] The utilization rate is derived from data in the Handbook of Energy & Economic Statistics of Indonesia 2016. It is based on the 2015 production figure of Coal Steam Power Plant of 130,508GWh (for both PLN and purchased power) and the installed capacity of coal steam power at 25.98GW, which translates into a total maximum generation of 227,565GWh in one year.

[16] The Jakarta Post. (April 2017). PLN to defer power plant projects totaling 9GW. www.thejakartapost.com/news/.../pln-defer-power-plant-projects-totaling-9-gw.html

internal rate of return (IRR) of between 20% and 25%.[17] Later coal power projects, those that achieved financial close from 2005 to 2009, such as Cirebon (660MW) and the Tanjung Jati expansion (2 x 660MW) have IRRs of between 12% and 14%.[18] In general, equity return for investors is higher than project IRR. The Indonesian government effectively guaranteed this return through capacity payment.

The high IRR attained in earlier years was commensurate with the political and commercial risk of investing in Indonesia, but the track record shows how much Indonesia has had to pay in order to kick-start and sustain the IPP momentum.

Capacity payments entrench PLN's financial obligations to IPPs. Such payments sky-rocketed after the Asian financial crisis of late 1997. A total of 27 IPP contracts were signed between PLN and IPPs at the time. PLN struggled financially to honor the IPPs, mostly with the take-or-pay clause under which PLN had to pay for the electricity no longer in need due to the economic downturn.[19]

Moreover, at the time, the payment for many of these IPPs was denominated in US dollars, while the revenue for PLN—the retail tariff—was in Indonesian rupiah. The depreciation of the rupiah saw the exchange rate plummet from 2,450 to 10,000 rupiah per dollar; the electricity tariff would have had to increase by 70% to reach its pre-crisis level.[20]

In February 1998, PLN unilaterally set an exchange rate of 2,450 rupiah per dollar for its payment to three IPPs when the rupiah was trading at about 8,450. By March 2003, PLN had reached agreements with 14 IPPs, and renegotiated tariffs were mostly in the range of USD 0.042-0.0493, significantly lower than the USD 0.0575-0.08 specified in the original contacts.[21]

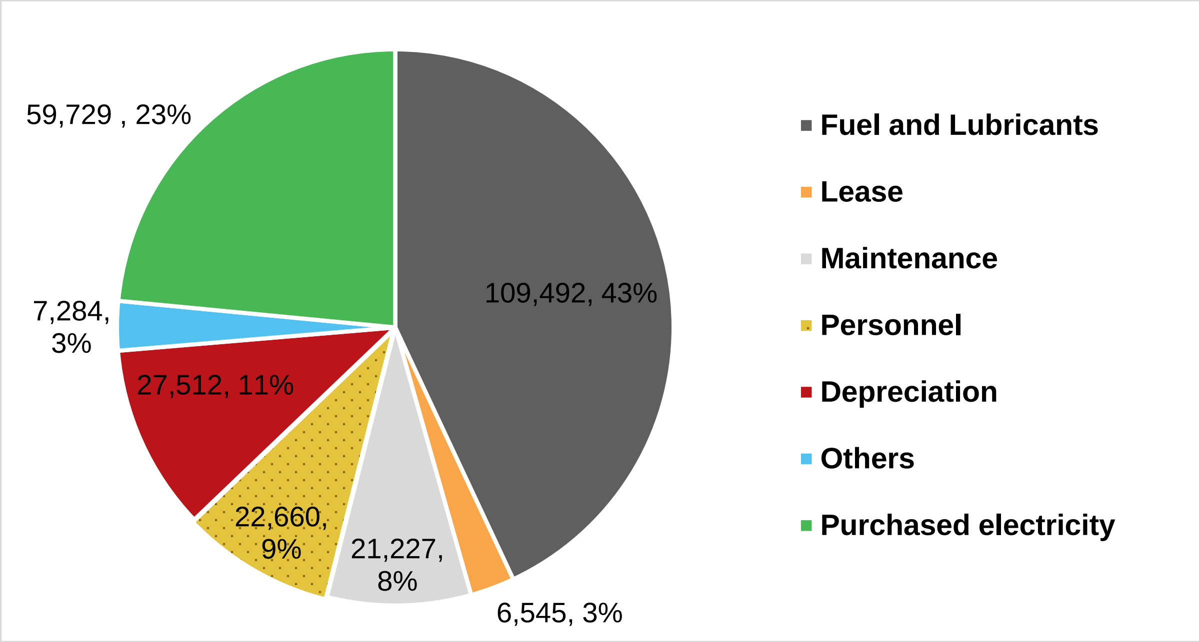
History has shown that the use of capacity payments has left the Indonesian government committed to significant long-duration outlays of financial obligations. If Indonesia were to experience any econmic downturn and/or currency depreciation in the future, it could face a scenario similar to the one it suffered during the Asian financial crisis. The last resort for PLN is to renege on its PPA obligations, or to renegotiate with IPPs due to financial difficulty, as this will raise sovereign risk and severely undermine the government's efforts to boost foreign direct investment. A default on PLN's obligations could lead to a cross-default of the company's government-guaranteed bank financing.

Endangering PLN's Financial Health

PLN spends an increasing amount to buy power from IPPs. In 2016, PLN spent IDR 59,729 billion on purchased electricity, representing more than 23% of total operating expenses.[22] See Figure 1.

[17] PwC. (November 2016). Power in Indonesia - Investment and Taxation Guide. November 2016 - 4th edition. www.pwc.com/id/en/pwc-publications/industry.../power-in-indonesia.html
[18] Ibid.
[19] Wu, X.; Sulistiyanto, P. National University of Singapore. (2013). Independent Power Producer (IPP) Debacle in Indonesia and the Philippines: Path Dependence and Spillover Effects. www.darryljarvis.com/uploads/2/2/6/9/22690064/ipp_debacle1.pdf
[20] Ibid.
[21] Ibid.
[22] PLN. (2016). PLN Annual Report 2016.

Figure 1: Purchased Electricity as a Share of Operating Expenses 2016 (IDR billion, Percentage)



PLN's financial obligations to purchase electricity from IPPs are set to increase, as the proportion of generation capacity assigned for IPP development is scheduled to increase from 2017 to 2026.

The financial obligations for capacity charges are all the more stark when analyzed against PLN's strained finances and its reliance on government subsidies. PLN's most significant revenue comes from power sales, contributing more than 96% of the total revenue at IDR 214,140 billion (US$16 billion) in 2016.[23] Consumer electricity prices are set by the government, at a lower level than the cost of generation. Despite the government's efforts to increase electricity tariffs over time, subsidies are still an important part of PLN's revenues, playing an essential role in bridging the gap between costs and revenues from electricity sales.

For PLN to cover more of its costs through electricity sales, tariffs must rise faster than costs. From 2010 to 2014 this was not always the case. The gap between generation costs and electricity tariffs are shown on a per-unit basis in Figure 2.[24] From 2010 to 2012, electricity tariffs remained relatively constant. Over the same period, costs rose much faster. From 2013, modification of tariff classes led to a rise in average tariffs, but they were still below costs.[25] [26] Revenue from customers in the last two years covered just 75-80% of PLN's production cost,[27] an unsustainable proposition.

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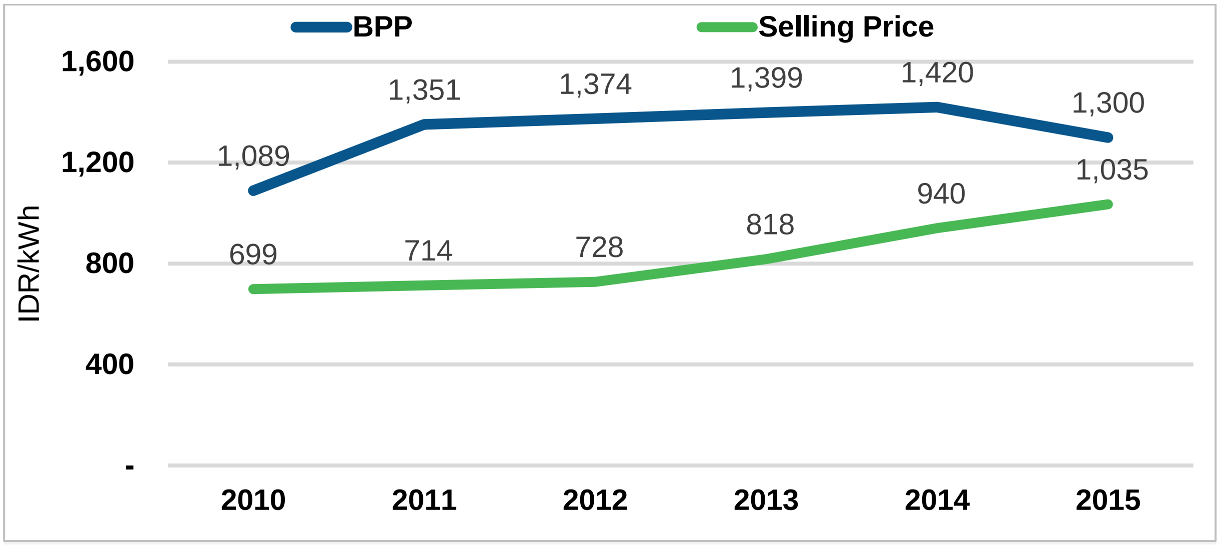
[23] PLN. (2016). PLN Annual Report 2016.
[24] PLN. (May 2016, April 2015) PLN Statistics 2015. Statistik PLN 2014. http://www.pln.co.id/2012/01/26/laporan-statistik/
[25] Tharakan, P. (December 2015). Summary of Indonesia's Energy Sector Assessment. ADB Papers on Indonesia. https://www.adb.org/sites/default/files/publication/178039/ino-paper-09-2015.pdf
[26] Global Subsidies Initiative. (September 2016). Indonesia's Financially Sustainable Electricity Sector. https://www.iisd.org/sites/default/files/publications/indonesia-financially-sustainable-electricity-sector.pdf
[27] PLN. (March 2017). Electricity Supply Buiness Plan (RUPTL 2017-2026).

Figure 2: Basic Cost of Electricity Production and Average Selling Price



Electricity subsidies have strained the Indonesian government's budgetary resources and they represent money not being invested in infrastructure or development. Subsidies have increased exponentially, from IDR 8.8 trillion (US$666 million) in 2005, to IDR 58 trillion (US$4.4 billion) in 2016.[28]

Since 2014, the government has embarked on a series of subsidy reforms. The government resolves to subsidize electricity supply to only poor and remote areas, and has reintroduced the automatic tariff adjustment mechanism, which allows for maintainance of the real price of services against fluctuation of various factors such as exchange rate and fuel price changes. The electricity subsidy is now being phased out gradually until all but the poorest households pay for electricity at market price by 2018.[29]

Nevertheless—even with these subsidies reforms—PLN will have significant negative cash flows due to large government-mandated investment plans through to 2020.[30]

The use of capacity payment for power undispatched will saddle PLN's limited budget and expose the Indonesian government to the risk of subsidizing underutilized thermal power plants for decades to come.

[28] Global Subsidies Initiative. (2016). 10 things you need to know about electricity subsidies in Indonesia. http://www.iisd.org/sites/default/files/publications/GSI%20info%20Graphic_0.pdf

[29] Tharakan, P. (December 2015). Summary of Indonesia's Energy Sector Assessment. ADB Papers on Indonesia. https://www.adb.org/sites/default/files/publication/178039/ino-paper-09-2015.pdf

[30] Fitch Ratings-Singapore. (May 2017). Fitch Rates Perusahaan Listrik Negara's Notes 'BBB-(EXP)'

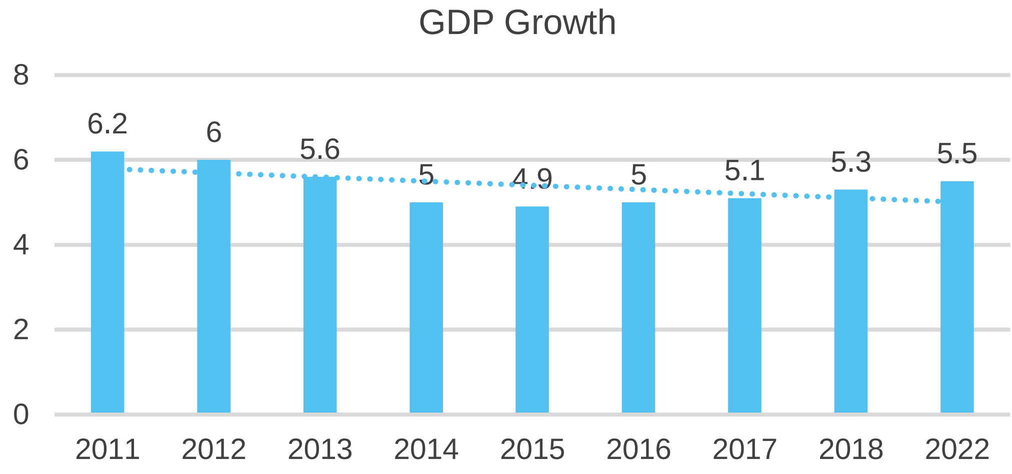
PLN Will Bear the Brunt of Misestimates of Future Electricity Demand

A key characteristic of a PPA is that the offtaker absorbs all market risk. PLN is responsible for developing an estimate of long-term power demand. If the demand does not meet expectations, PLN is obligated to pay for the contracted amount under the PPA's take-or-pay provisions.

PLN acknowleges this risk. As it states in its 2017-2026 RUPTL, if additional power generation capacity is added as planned but realized economic growth is lower than assumed, the result will be over-capacity and will in time increase telectricity supply cost (*biaya penyediaan pokok)*, or BPP, because of the existence of the take-or-pay scheme in PPAs with IPPs.[31]

Electricity demand growth is a function of economic growth. The country's 35GW program was designed with annual economic growth of 7% in mind. Based on this assumption, Indonesia will require 7GW of new electricity capacity annually through 2019[32]. However, Indonesia's GDP has grown at (a still respectable) compound annual growth rate of 5.5 percent in the past five years and the International Monetary Fund (IMF) projects growth in 2017 to be 5.1%[33] (see Figure 3)—both well short of the overly optimistic 7% target.

Figure 3



Source: IMF World Economic Outlook.

Slower-than-forecast growth has led to a downward revision of the country's plan to add only 15GW of capacity by 2019, according to Energy and Mineral Resources Minister Ignasius

[31] PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).
[32] PLN. (Retrieved May 2017). http://www.pln.co.id/35000mw/en/#s1
[33] International Monetary Fund. (April 2017). World Economic Outlook. http://www.imf.org/en/Publications/WEO/Issues/2017/04/04/world-economic-outlook-april-2017

Jonan.[34] The challenge in sales projections is borne out by a series of downward adjustments of electricity sales projections by different government departments,[35] see Figure 4. Such overestimation of electricity demand growth is nowhere near unique to Indonesia, with countries from Japan to China and India all hobbled by excess generation capacity expansion plans that are resulting in immediate idling of new thermal power capacity. The end result: collapsing utilisation rates of thermal power plant in 2016 to below 50% in China and below 60% in India—despite utility projections of 70-80% utilisation rate averages.

Figure 4 Comparison of Projections of Electricity Sales

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Draft RUKN 2015-2034	262	287	315	347	382	420	462	508	559	616	654
RUPTL 2016-2025	225	244	268	292	315	340	366	394	425	457	
RUKN 2008-2027	285	312	342	376	413	454	499	549	605	667	736
Draft RUPTL 2017-2026	218	235	254	276	302	330	357	386	417	450	483

Further revisions may be required. RUPTL 2017-2026 was formulated based on economic growth of 6.2% for the covered period (see Table 8), against the IMF forecast of 5.1% for 2017 and 5.5% for 2022. Similarly, The World Bank forecasts Indonesia GDP to grow at 5.5% for 2018 and 2019.[36] Indonesia may not require 77,873MW of installed capacity as envisioned by 2026.

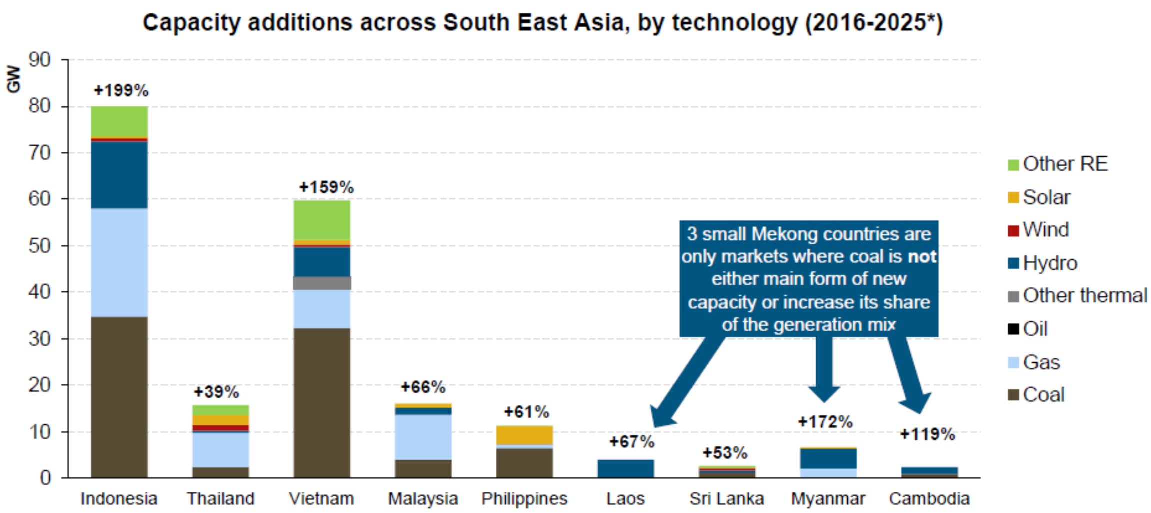
[34] The Jakarta Post. (January 2017). Indonesia only needs 15,000MW extra electricity by 2019: Minister. http://www.thejakartapost.com/news/2017/01/25/indonesia-only-needs-15000-mw-extra-electricity-by-2019-minister.html
[35] PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).
[36] World Bank Group. (January 2017). Global Economic Prospects. Weak Investment in Uncertain Times. https://openknowledge.worldbank.org/bitstream/handle/10986/25823/9781464810169.pdf?sequence=5&isAllowed=y

Table 8: Summary of Changes to RUPTL 2017-2026 in Comparison to Previous Covered Period

Description	Unit	RUPTL 2016-2025	RUPTL 2017-2026
Assumed Economic Growth	%	6.7	6.2
Assumed Electricity Growth	%	8.3	8.3
Electrification Ratio	%	99.7	100
Power Plant	MW	80,538	77,873

Indonesia's previous capacity addition plans have already shown to be out of step with other Association of Southeast Asian Nations (ASEAN) countries such as Vietnam and the Philippines, economies forecast to grow by 6.2% and 7%, respectively, in 2022[37]. Those growth-project rates are higher than Indonesia's 5.5% but neither Vietnam nor the Philippines have planned for additions as large as Indonesia's.[38] See Figure 5.

Figure 5



The 35GW programme is excessive considering that the additional capacity (42.9GW taking into account ongoing projects from Fast Track Program phase 1 and 2) represent 81 percent of Indonesia's installed power capacity at the end of 2014.[39]

Indonesia would be far better served by setting and investing in ambitious national energy efficiency targets—the cheapest generation capacity is one that isn't required. Mandated industrial equipment, appliance efficiency ratings and tighter building codes can collectively

[37] International Monetary Fund. (April 2017). World Economic Outlook. http://www.imf.org/en/Publications/WEO/Issues/2017/04/04/world-economic-outlook-april-2017
[38] The Lantau Group. (September 2016). New trends in the South East Asia power industry and key implications for Myanmar in the short and long-term.
[39] Cornot-Gandolphe, S. The Oxford Institute for Energy Studies. (March 2017). Indonesia's Electricity Demand and the Coal Sector: Export or meet domestic demand?

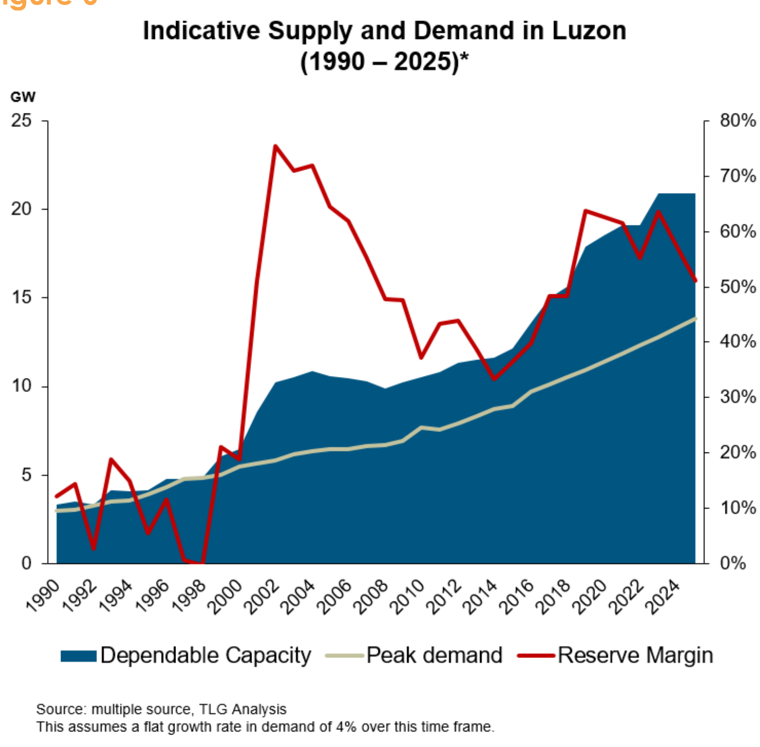
drive sustained energy productivity gains that would better serve Indonesia's international competitiveness.

The Effectiveness of Capacity Payment Elsewhere Is Questionable

The capacity payment system is not unique to Indonesia, or other developing countries that use it to encourage private sector investment in power generation. Countries have used capacity markets to facilitate growing generating capacity, regardless of whether they generate electricity, and have done so in the interests of energy security.

In the Philippines, the electricity sector has consistently been plagued, however, by a mismatch between demand and supply. In the 1980s, Luzon was plagued by eight-hour brownouts. There were no large thermal power stations because the Philippines has just come out of a political upheaval that bankrupted the country. After this period, the only way to attract investors was to include sovereign guarantees in the PPAs in take-or-pay contracts. This has resulted in more plants being built than required with the reserve margin forecast at over 50% by 2024 in Luzon. Figure 6[40] shows the supply glut from 2002 to 2024.

Figure 6



[40] The Lantau Group. (May 2017). Incentivising More Efficient Generation Under Current DOE & DENR Rules. http://www.lantaugroup.com/files/ppt_pewp17_sf.pdf

In Europe, capacity market schemes pay operators per kilowatt per year through administered prices (e.g. Spain) or reverse auctions (e.g. the U.K.). Such schemes are used to the same purpose in the U.S., where utilities have suffered from reduced profitability due to declining demand and lower prices to the point where investors are deterred from making long-term investments.

While recognizing that Indonesia is at a different stage of development of its electricity sector, studies have shown that there is little weight in arguments that 25-30 years of locked-in capacity payments are needed to incentivize investment.[41]

Spain introduced a capacity market in 1997 to drive investment in gas generation when the economy was growing rapidly. Growth subsequently collapsed, however, and the scheme led to massive over-capacity, while proving difficult to roll back.[42]

The U.K. introduced a capacity market in 2014 with the aim of driving investment, both to help phase out coal power whilst ensuring back-up generation for variable renewables. While the goal of the capacity market was to drive investment in reliable new generation, the U.K. scheme—with £3.4 billion in awarded contracts to date—has yet to incentivize a single large new power plant. Support has instead gone to subsidize outdated investments, including more than £450 million for existing coal-fired power plants.[43]

The U.K. and Spanish capacity markets provide greater support for more polluting, so-called baseload generation, such as gas and coal, rather than more modern approaches that support renewables, such as demand-response, interconnection and battery storage. There is a risk that they thus perpetuate an inflexible electricity system over a more nimble, modern digital alternative.

There are also big questions over capacity markets' real reason for exisiting. In Spain and the U.K., these markets favour ailing or older coal-and gas power plants as a result of intense lobby pressure from struggling utilities.

Indonesia will continue to require capacity payments to attract IPP investment for thermal power generation. However, the more entrenched these financial commitments are and the farther they stretch into the future, the more likely Indonesia will follow in the footsteps of Europe, where capacity payments serve the narrow interests of aging and under-utilized thermal power plants.

Economical Alternatives to Capacity Payments

A consequence of the use of capacity payment is the shielding of thermal IPPs from competition of cheaper energy sources such as solar and wind. This section outlines PLN's past financial challenges to procuring renewables, but notes that significant global deflationary

[41] Hirth, L., Ueckerdt, F. Ten propositions on electricity market design: Energy-only vs. capacity markets. https://www.iaee.org/en/publications/proceedingsabstractpdf.aspx?id=12385

[42] Wynn, G. IEEFA. (December 2016). Spain's Capacity Market: Energy Security or Subsidy. http://ieefa.org/wp-content/uploads/2016/12/Spain%E2%80%99s-Capacity-Market-Energy-Security-or-Subsidy_December-2016.pdf

[43] Wynn, G. IEEFA. (March, 2017). Electricity Grid Transition in the U.K. As Coal-Fired Generation Recedes, Renewables and Reliable Generation Can Fill the Gap. http://ieefa.org/wp-content/uploads/2017/03/Electricity-Grid-Transition-in-the-U.K._March-2017.pdf

trends in renewables now offer an economical alternative that is in the interest of PLN and in the interest of the country's budget and can facilitate the achievement of universal electrification at the lowest cost possible.

PLN Is Disincentivized From Procuring Renewables as Utilization Rates of Thermal Plants Drop

PPAs for power generated from intermittent renewable energy sources such as wind and solar are drawn on a must-run basis, up to 10MW, in that PLN is obliged to dispatch qualifying projects if they are producing energy over baseload plants. Solar and wind energy producers get paid only for every unit of kWh dispatched.

As renewables become cheaper and contribute a greater proportion of the overall energy mix, PLN will face the prospect of having to continue to make locked-in capacity payments to thermal power IPPs even though less power is sourced from these plants.

Renewables generate electricity at close-to-zero marginal cost when the sun or the wind is available. As such, it only makes sense for their power to be dispatched ahead of that from more expensive thermal plants, which have fuel costs and higher running or variable costs. Economic efficiency means that thermal plants will invariably be called upon to generate electricity less and less of the time, resulting in lower utilization rates and lower plant efficiencies.

Capacity payments have the effect of disincentivizing PLN from procuring more renewable energy to avoid paying capacity charges for under-utilized thermal plants.

Renewable energy is already encroaching on the market share of coal-fired power plants in China and India, where plant utilization rates have declined. In China, the average utilization rate dropped from just over 60% in 2011 to a record low 47.5% in 2016.[44] Similarly, in India, the prolonged annual addition of 15GW annually of new coal-fired power plants has been met with significantly weaker-than-forecast electricity demand growth. The result: India's coal-fired power sector utilization rate has fallen from 75% in 2011 to 59% in the first nine months of 2016/17.[45]

Signs of this happening in Indonesia are appearing now. As a result of slower-than-expected economic growth, power plants, particularly those dating from the initial phase of President Susilo Bambang Yudhoyono's 2x10,000MW Fast Track Program phase 1 and 2, are operating well below capacity, some running at just 30-45% of planned output.[46]

IEEFA's analysis of Indonesia's power consumption finds that in 2015, coal-fired power plants in Indonesia operated by PLN and IPPs operated on average 57.3% of the time. Developers and PLN had forecast a utilization rate of 80%.

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[44] Buckley, T. (March 2017). Japan's 'Rising Sun' Drives Energy Sector Transformation. http://ieefa.org/japans-rising-sun-drives-energy-sector-transformation/

[45] Buckley, T. (November 2016). Electricity-Sector Transition Picks Up Speed. http://ieefa.org/ieefa-data-byte-indias-electricity-sector-transition-picks-speed/

[46] FT Confidential. (December 2016). Indonesia's power target increasingly far-fetched. http://app.ft.com/cms/s/8de6867a-c78a-11e6-8f29-9445cac8966f.html

The merit-order effect describes the lowering of average power prices at an electricity exchange due to an increased supply of renewables. The power price is determined by the merit order—the sequence in which power stations contribute power to the market, with the cheapest offer made by the power station with the lowest marginal running costs setting the starting point. Power from renewable installations such as wind turbines and PV push conventional power producers down the merit order.[47]

Thermal power stations owned by IPPs (and by PLN) will be vulnerable to being pushed out of the market more and more because they cannot compete against near-zero marginal costs of a PV plant or a wind farm. Indonesia's goal of achieving energy security at the lowest cost possible will be rendered impossible if PLN continues locking in multi-decade capacity charges.

Coal-Fired Power Is Too Inflexible to Incorporate Variable Renewable Energy

Coal-fired power plants operate with least loss of thermal efficiency when in constant production. However, as the share of intermittent renewables rises, so will the need for thermal technologies to balance the resultant variable generation. Future coal-fired plants will need the flexibility to balance fluctuations in the power system, otherwise, they cannot act as a feasible spinning reserve for variable renewable energy due to their low ramp up and ramp down rate.

If a coal-fired plant does not operate at a high capacity factor, the cost of generating each unit of electricity increases[48]. Investments in these plants, especially ones with higher efficiency boilers, are commercially viable only when the plant is optimized at full load with high capacity factor.

Another effect of increased supply from renewables, particularly solar power, is the flattening out of the daily lunchtime peak price at the power exchange. With solar power production peaking around noon, this coincides with the time of high demand, again weakening demand to dispatch from coal fired power plants. Any sustained development of renewable energy infrastructure should come with an associated plan for time-shifting demand through demand-response management and incrementally building out electricity storage capacity (distributed rooftop solar with behind the meter batteries) and/or adding rapid commencement peaking capacity (gas and hydro-electricity).

All these factors will contribute to falling utilization for coal-fired power plants as electricity sector technology developments continue to accelerate globally, all of which will translate into a financial burden for PLN in paying for un-dispatched power.

[47] Clean Energy Wire. (January 2015). Setting the power price: the merit order effect. https://www.cleanenergywire.org/factsheets/setting-power-price-merit-order-effect

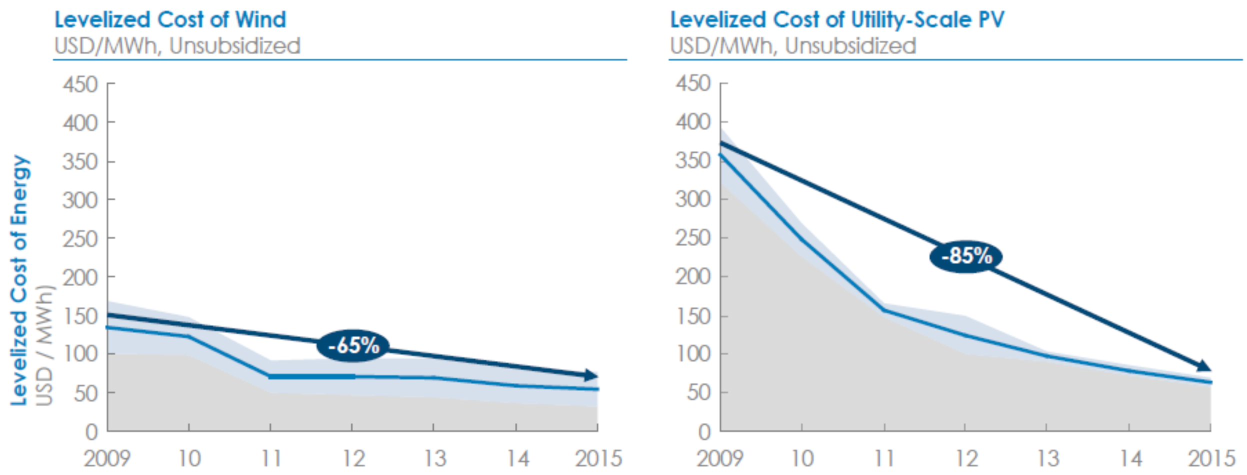
[48] IEA. (2012). Technology Roadmap. High-Efficiency Low-Emissions Coal-Fired Power Generation. http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapHighEfficiencyLowEmissionsCoalFiredPowerGeneration_WEB_Updated_March2013.pdf

Cheaper Renewables Are Coming to Indonesia

Levelized cost electricity (LCOE) is used as a summary measure of the overall cost to build and operate a power plant using a specific technology over its lifetime. The cost is typically set per-kilowatt-hour. LCOE is determined largely by two costs: i) Engineering, procurement, construction (EPC) contracts; and ii) financing. Both are falling in Indonesia.

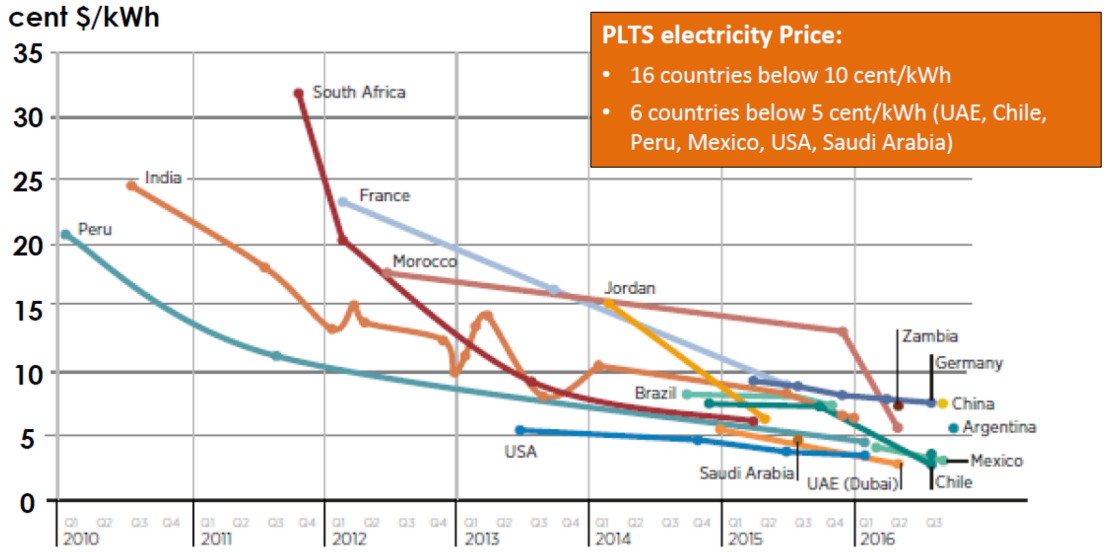
First, EPC prices. The bid prices for utility solar PV and wind projects in Europe, the Middle East, China and India have been falling significantly thanks to tumbling equipment prices driven by rapidly rising economies of scale and continued technology improvements, see Figure 7[49] and Figure 8[50]. While Figures 7 and 8 detail renewable energy deflation from 2009-2015, the trends depicted have actually accelerated in 2016 and in 2017, with renewable power tariffs increasingly evident at US$24-45/MWh, often with zero inflation indexation built in for the 25-year contract duration.

Figures 7 and 8



49 Energy Transitions Commission. (April 2017). Better Energy, Greater Prosperity. http://energy-transitions.org/sites/default/files/BetterEnergy_fullReport_DIGITAL.PDF
50 IRENA. (2017). Rethinking Energy 2017. http://www.irena.org/DocumentDownloads/Publications/IRENA_REthinking_Energy_2017.pdf

Electricity price development of solar energy ("PLTS") in various countries



Sumber: IRENA, *Rethinking Energy 2017, 2017*

Compared to the current cost of non-renewable power generation, the potential for renewable deployment in Indonesia based on competitive grounds exists already in rural regions where the increasing use of imported diesel and oil make electricity generation expensive.

Second, the cost of financing. Downward shifts in EPC prices raise important financing issues. The cost structure of renewable projects, with high upfront capital and low operating cost, makes the cost of capital, and therefore the perception of risks, particularly important. The typical commercial cost of capital in Indonesia is higher than 10% for local currency or USD-denominated lending. This has resulted in a relatively high PPA tariff for renewable projects in the past.

However, Indonesia's central bank lowered rates six times in 2016.[51] The country has also been rated investment grade by all three major rating agencies for the first time since the Asian financial crisis, following Standard & Poor's decision in May 2017 to lift Indonesia's rating of its sovereign debt to investment grade. The upgrade allows Indonesia to access a massive pool of eligible foreign investors that only invests in at least investment-grade-rated assets. This will progressively lower funding costs[52], particularly if favourable low-emission energy plans be accelerated with a degree of long-term certainty, substantial scale and policy clarity.

[51] Straits Times. (April 2017). Indonesia central bank holds interest rate as inflation concerns loom. http://www.straitstimes.com/business/indonesia-central-bank-holds-interest-rate-as-inflation-concerns-loom

[52] Financial Times. (May 2017). Indonesia rated investment grade by all major agencies as S&P upgrades. https://www.ft.com/content/61b7edd6-244a-3cab-a90c-f3cda71023db

Coal Power Is Inflationary

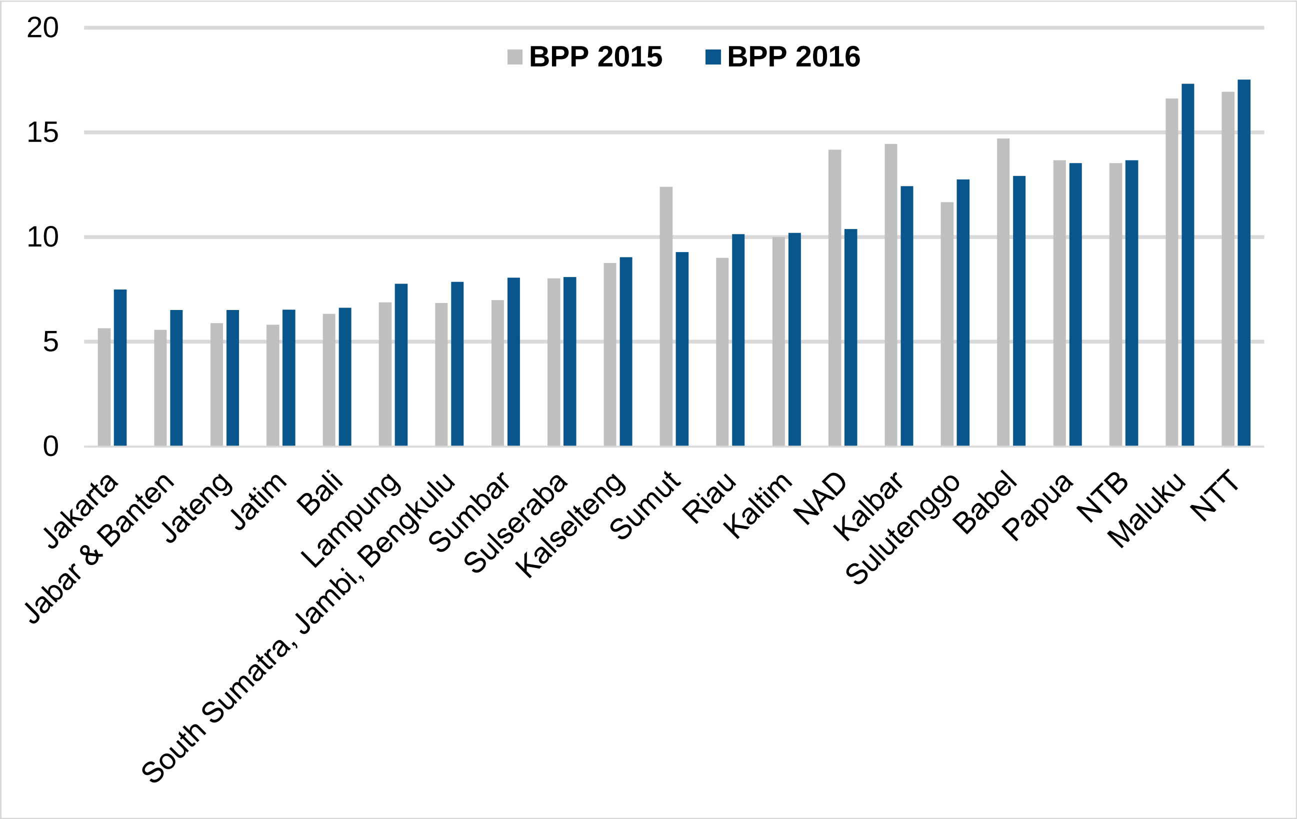
The variable cost of generating from a thermal power plant is a function of the costs of fuel and operation and maintenance (O&M), both of which are linked to inflation. Fuel cost is a pass-through cost in thermal power PPAs, in that PLN bears the cost of the fuel. O&M costs account for 15% of the total and fuel costs for some 35%. As a general guide on tariff proposals as stipulated by PLN, half of fixed O&M charges are indexed to the US Consumer Price Index (USCPI) and the rest to the Indonesian Consumer Price Index (ICPI). For variable O&M charge, 25% of this portion is indexed to the USCPI and 75% to the ICPI.[53] In Indonesia, the levelized generation costs of coal-fired power plants is US$55/MWh.[54]

In spite of the advantages coal-fired power plants in Indonesia have owing to cheap coal supply, inexpensive local equipment, and low labour costs, a significant increase has occurred in the cost of baseload technologies, such as coal-, gas-fired and nuclear power plants. This is borne out in comparing 2015 results of an IEA/NEA study against that of the 2010 study on the same subject.[55]

This sustained thermal power cost inflation is borne out, too, by comparing the cost of power generation (BPP) in Indonesia between 2015 and 2016. A total of 16 of 21 provinces have seen their regional BPP increase. See Figure 9. The BPP consists of cost of oil fuels and non oil fuels (maintenance, workers etc.). The factors affecting the BPP are highly dependent on the macroeconomic variables such as exchange rates, inflation and prices of primary energy sources.[56]

[53] PLN. (December 2014). Part 1 Bid Document. Request for Proposals For the Development of (2x100MW) Bengkulu CFSPP (Coal-Fired Steam Power Plant) IPP Project.
[54] Bloomberg New Energy Finance (October 2016). H1 2017 APAC LCOE Update.
[55] Ibid.
[56] PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).

Figure 9: Cost of Power Generation (BPP) in Selected Regions (USD cents/kWh)



Source:MoEMR no. 1404 k/20/MEM/2017 dated 27March 2017[57]

Moreover, the mining industry itself has expressed concerns about the availability of coal supply for domestic power generation if market prices do not recover sufficiently to incentivize capital expenditure. By one estimate, at current rates of consumption and when coal is cheap (as it was when they fell to US$50.9/tonne in February 2016), proven coal reserves would last until 2036, well short of the operational lives of planned power plants.[58]

Thermal coal price volatility has increased as energy market transitions have acelerated. The latest thermal coal reference price (Harga Batubara Acuan or HBA) has increased materially over the past year to US$83.81/tonne in May 2017,[59] but geopolitical shifts that affect countries' appetite for coal do not help. Government-induced output cuts in China are unlikely to offer strong price support on top of more structural decline seen in Indian imports of thermal coal. South Korea will also slow imports as president Moon Jae-In was voted in with a promise to re-assess the construction of new coal power plants, close older ones and dramatically ramp up national renewable energy goals.

[57] PwC. (April 2017). Investing in Power: Risks under the new PPA and tariff regulations for renewables. http://www.pwc.com/id/en/publications/assets/eumpublications/newsflash/2017/eum-newsflash-2017-61.pdf

[58] PwC. (March 2016). Supplying and Financing Coal-Fired Power Plants in the 35GW Programme. http://www.apbi-icma.org/wp-content/uploads/2016/03/03-03-2016-APBI-PwC-Report-on-Supplying-and-Financing-the-35-GW-program-FINAL-FINAL-rev-8-32016.pdf

[59] Platts. (May 2017). Indonesia sets HBA thermal coal price for May up 64% on year at $83.81/mt. https://www.platts.com/latest-news/coal/singapore/indonesia-sets-hba-thermal-coal-price-for-may-27826091

PLN faces the prospect of a no-win situation. If the long-term forecast for coal prices is downward and local production is suppressed, PLN may not be able to avoid the eventuality of having to import coal to support domestic coal-fired power plants. If the coal price recovers enough to incentivize global production, coal as a fuel becomes expensive for power plants and for PLN as coal price is principally a pass-through for IPP projects[60].

Indonesia also faces another dilemma, between the need to use coal for domestic power consumption and the desire to increase coal exports. Because the government is concerned that the country may exhaust reserves unless output controls are enforced, the National Development Planning Agency has set a target of 413 million tonnes for 2017, and a production cap of 400 million tonnes from 2019 onward in an effort to secure supply to meet growing domestic demand.

But local mining companies have resisted the restriction and 2017 production is expected to climb 5% in 2017 and 2018 from an estimated 440 million tonnes in 2016. This is set against the government's needs to lean on revenue from coal exports to make up shortfalls on its take from oil and gas, both in terms of output and value. Indonesia is targeting a 20 percent increase in non-tax revenues from the mining sector, which includes coal, in 2017, to 32.48 trillion rupiah (US$2.44 billion), up from 27.15 trillion rupiah in 2016, in hopes of replacing declining oil returns[61].

Renewables Are Deflationary

MEMR implemented Regulation No. 12/2017 on the Utilisation of Renewable Energy Resources for Electricity Supply in February 2017. The new regulation covers power purchase from all existing renewable energy types such as solar PV, wind, hydropower, biomass, biogas, municipal waste, and geothermal. It uses the regional PLN's cost of electricity supply (biaya penyediaan pokok/BPP) as its new reference price in each market. Most power plants in Indonesia are using fossil fuels (mainly cheap coal and gas) and their cost of power generation is reflected in the BPP.

Currently, electricity costs from most renewable technologies in Indonesia are higher than the local BPP, specifically in Java and Bali where more than 70% of the country's total installed capacity exists. This high cost and the uncertainty in recovering this cost from the government through subsidies have driven PLN to be reluctant to procure renewable energy from IPPs in the past.

The regulatory change alters this dynamic. It has the effect of lowering PLN's financial burden through indexing all renewable energy tariffs to PLN's regional production costs. Most renewable energy tariffs will be capped now at 85% of the regional generation cost, if this price is higher than the national average generation cost. If the regional generation cost is the same or lower than the national average, then the limit will be 100% of the regional generation cost.

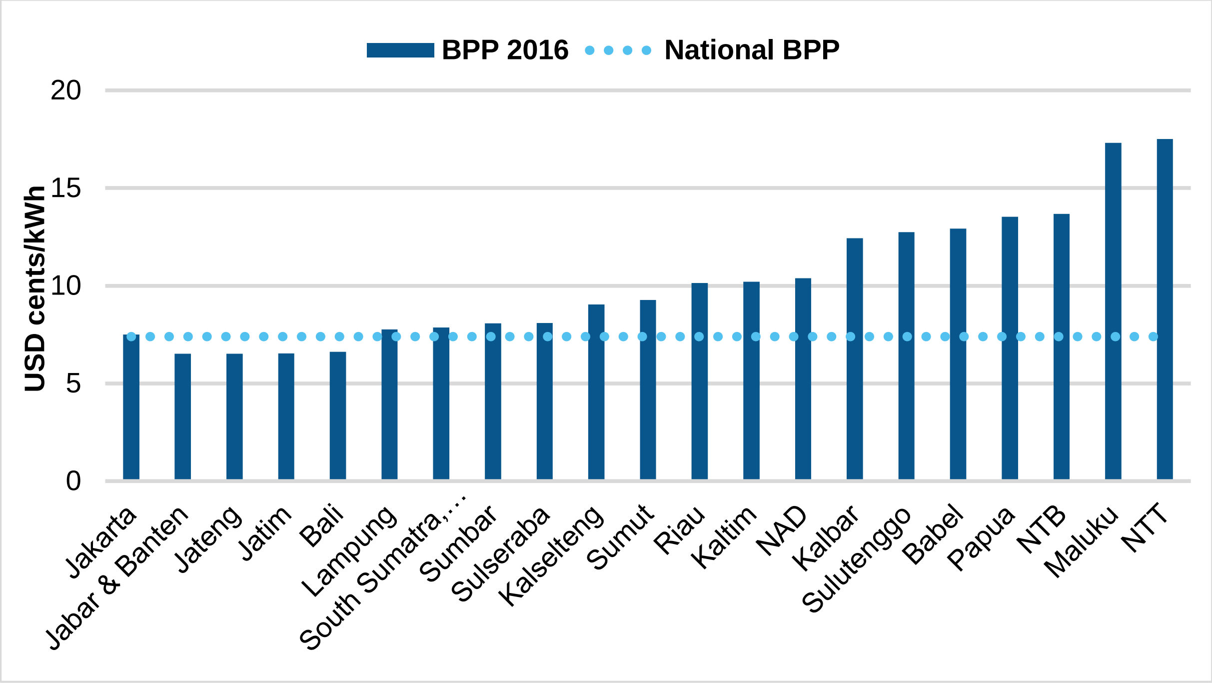
[60] PwC. (November 2016). Power in Indonesia - Investment and Taxation Guide. November 2016 - 4th edition. www.pwc.com/id/en/pwc-publications/industry.../power-in-indonesia.html

[61] Reuters. (May 2017). Indonesia's revenue needs override coal curbs as oil take drops. http://www.reuters.com/article/us-indonesia-coal-supply-idUSKBN18K0QJ

By bringing down the renewable price to the same level or less than the regional BPP, it is expected that PLN will utilize more renewable-generated power.

This approach means that IPPs operating in certain regions enjoy higher tariff than in others where PLNs regional production costs are higher. Currently, the 2016 audited national average production cost in Indonesia is about US 7.4 cents per kWh, while local production costs vary from region to region. For example, the current local production cost in Papua is about USD 13 cents per kWh, while in certain areas in Java the cost is about USD 6 cents per kWh. See Figure 10.[62] Renewable energy will initially only be competitive in outer regions, where the local BPP is considerably higher than the national BPP.

Figure 10: BPP for Selected Regions in Indonesia



While the new regulation effectively discourages developers from looking at sites in Java and Bali, where currently more expensive renewable technologies cannot compete on costs with coal-fired power plants, the trend of decreasing EPC and financing costs for PV and wind projects will continue. As deployment increases, it will facilitate learning by doing in the domestic context, and will soon allow renewables to be increasingly competitive even on Java-Bali grids.

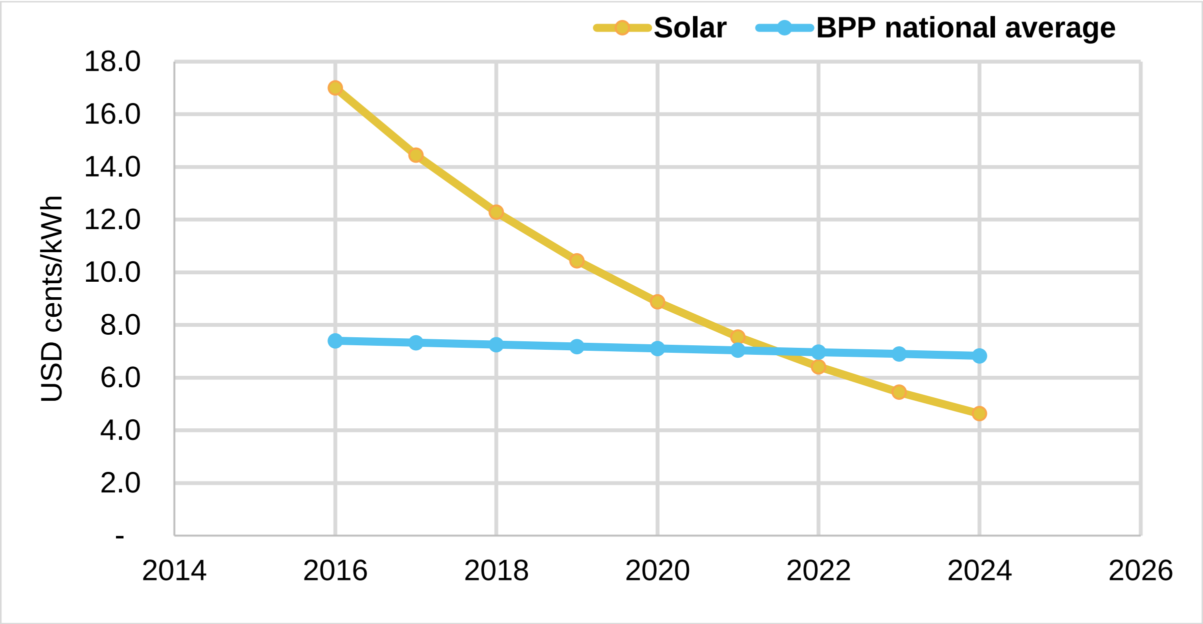
The LCOE for solar in Indonesia is estimated at USD 17 cents/kWh in 2016.[63] By comparing the downward price movement of solar PV prices realized at auctions against the inflationary prices of thermal power and the impact of Regulation 19/2017 (which caps the tariff for small scale coal-fired power and mine-mouth plants), the trajectories of both will converge at around USD 8 cents/kWh in 2021. This assumes a deflation of 15% per annum for solar LCOE

[62] ASEAN Centre for Energy. (March 2017). Renewable Energy Power Pricing in Indonesia. http://www.aseanenergy.org/blog/renewable-energy-power-pricing-in-indonesia/

[63] Ibid.

and a deflation of 1% per annum for BPP, considering the effect of an inflation-indexed fossil fuel cost and the impact of Regulation 19. This suggests solar PV will become grid competitive in 2021 on average, and that Java and Bali will follow this trend soon afterwards. See Figure 11.

Figure 11: Convergence of Solar LCOE and BPP National Average



Source: IEEFA analysis. This assumes a deflation of 15% per annum for solar LCOE and deflation of 1% per annum for BPP.

According to an analysis by the Energy Transitions Commission, by 2035, it will be feasible in many areas to build a near-total-variable-renewable power system providing electricity at a maximum all-in cost of USD 7 cents per kWh,[64] even fully accounting for peaking demand, electricity storage and grid stability.

Regulation 12 also stipulates the use of auctions to award solar and wind capacity. Previously, solar and wind projects followed a first-come, first-serve allocation and business-to-business unsolicited bid negotiated approach. Many markets have shown that reverse auctions will lead to price discovery and generally results in the downward spiral of PV tariffs seen in India, for instance, see Table 9.[65] Recent reverse auctions in Germany and Spain in 2017 have likewise driven over 20% year-on-year declines in winning tariff rates for both solar and wind.

[64] Energy Transitions Commission. (April 2017). Better Energy, Greater Prosperity. http://energy-transitions.org/sites/default/files/BetterEnergy_fullReport_DIGITAL.PDF

[65] Buckley, T. (May 2017). India's Electricity-Sector Transformation Is Happening Now. http://ieefa.org/ieefa-asia-indias-electricity-sector-transformation-happening-now/

Table 9

Month/Year	Technology	Capacity	Tariff
May 2017	Solar	500MW	Rs2.44/kWh, USD3.8 cents/kWh
May 2017	Solar	250MW	Rs2.62/kWh, USD4 cents/kWh
February 2017	Solar	750MW	Rs2.97/kWh, USD4.6 cents/kWh

Source: IEEFA

Solar power potential is gauged by Global Horizontal Irradiation (GHI), a measurement of the intensity of the sun. Indonesia has a GHI that can produce 1,800 to 2,200 kilowatt-hours of solar power per square meter (kWh/m2), up to double the 1,000 to 1,200kWh/m2 in Europe's solar leader, Germany, according to solar weather and data provider Solargis.[66] So far, MEMR's outlook for the power sector sees increased capacity sourced from utility, rooftop and off-grid solar to 9.3GW by 2030[67]. IRENA sees 47GW by 2030, while IEEFA sees 33GW of solar potential that can be realistically tapped after considering land and rooftop space constraints[68] and grid stability needs. Diversity of electricity system generation will enhance Indonesia's energy security.

Regulation 12 aims to support the government in achieving a 23% renewable share target in the national energy mix by 2025. This is aligned with MEMR's direction to provide the most affordable electricity. Pricing is no longer a constraint to renewable growth. What is needed is sustained policy support. This adjustment on electricity pricing is crucial to lowering the existing BPP at the associated local grids. Continuing capacity charge to thermal plants, on the other hand, will lock in payments for electricity that PLN does not dispatch for the next 25 years.

Renewables Are the Cheapest Way to Achieve Universal Electricity Access

Indonesia, an island nation, lays claim to having the largest population of islanders. Many Indonesian islands, especially those in the range of 1,000 to 100,000 inhabitants each, rely on diesel generators for their electricity production and spend a considerable percentage of their GDP on the import of fuels. In most cases, renewables have already been proven to be a cost-effective replacement for imported diesel generators, a reality that has been in place since 2013[69] even though very little has been done to implement renewables.

[66] Solargis. Retrieved on 8 June 2017. http://solargis.com/assets/graphic/free-map/GHI/Solargis-Indonesia-GHI-solar-resource-map-en.png

[67] International Renewable Energy Agency (IRENA). (March 2017). Renewable energy Prospects Indonesia. This is based on targets set in the National Electricity General Plan (RUKN) and the National Energy Policy (KEN). http://www.irena.org/DocumentDownloads/Publications/IRENA_REmap_Indonesia_report_2017.pdf

[68] International Renewable Energy Agency (IRENA). (March 2017). Renewable energy Prospects Indonesia. http://www.irena.org/DocumentDownloads/Publications/IRENA_REmap_Indonesia_report_2017.pdf

[69] IRENA. (2015). Off-grid Renewable Energy Systems: Status and Methodological Issues. https://www.irena.org/DocumentDownloads/Publications/IRENA_Off-grid_Renewable_Systems_WP_2015.pdf

PLN's rural electrification plan is still driven by expensive imported diesel fuel. It aims to develop diesel-fuelled power plants for villages that are growing but have not yet secured connection from the expansion of the nearest grid system.[70]

Indonesia had attained 88.3% electrification as of end of 2015.[71] The government aims for near-universal access by 2020, according to the National Energy Policy (Kebijakan Energi Nasional, KEN) adopted in 2014. While the challenge of electrification is most acute in eastern Indonesia, the province of West Java has nearly as many unelectrified households—some 2.4 million—as all of eastern Indonesia combined. There is mixed access to the grid, with electrification in the western part of the country as high as 99.97% (Bangka Belitung), and in the eastern part of the country as low as 45.9% (Papua).[72]

The approach to electrification through large-scale capacity additions that previously served the country well are increasingly ill-suited to the conditions the sector now faces as it aims to electrify the remaining 16% of its population, representing some 40 million people. In addition to this base of households without electricity, Indonesia has natural growth of some 900,000 new households per year.[73]

Electrification efforts must now extend to more remote settlements, which are costlier and technically more difficult to serve. Increased use of fast-to-install renewable mini-grids and individual off-grid household systems represents a least-cost modular option to bring electricity to the last clusters of unserved populations.[74]

Conclusion

PLN will be contracted to pay US$76 billion in capacity payment to secure access to coal-fired capacity scheduled to be added from 2017 to 2026. This payment will lock in financial commitments for the duration of the PPAs, mostly for a period of 25 years.

There is a better approach: Procuring electricity from renewable energy sources such as wind and solar whose producers are paid only for every unit of kWh dispatched, not for capacity that is not dispatched. As these sources become cheaper and contribute a greater proportion of the overall energy mix, PLN will face the prospect of having to continue to make capacity payment to coal-fired power IPPs even as less power is sourced from these plants.

This report does not argue for discontinuing the use of capacity payments to encourage private sector investment. Rather, it presents the economical alternative of renewable energy and the advantages of having a diversity of energy sources in the power generation portfolio in order to achieve national energy security.

70 PLN. (March 2017). Electricity Supply Business Plan (RUPTL 2017-2026).

71 MEMR. (July 2016). Handbook of Energy & Economic Statistics of Indonesia 2016. https://www.esdm.go.id/assets/media/content/content-handbook-of-energy-economic-statistics-of-indonesia-2016-lvekpnc.pdf

72 PwC. (November 2016). Power in Indonesia - Investment and Taxation Guide. November 2016 - 4th edition. https://www.pwc.com/id/en/energy-utilities-mining/assets/power/power-guide-2016.pdf

73 ADB. (2016). Achieving Universal Electricity Access in Indonesia. https://www.adb.org/sites/default/files/publication/182314/achieving-electricity-access-ino.pdf

74 Ibid.

As PLN commits to 25- to 30-year PPAs at a fixed tariff with an inflationary fuel and O&M price escalation built in for coal-fired power plants, it does so in a time that coincides with double-digit annual renewable tariff deflation supported by falling funding costs. The upshot is that the former will become unjustifiably expensive. It would be an imprudent use of public funds for the state-owned utility and sole purchaser of electricity to commit large amounts of its budget for long-duration capacity payment, as coal-fired power plants will become underutilized and economically uncompetitive in the near future.

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Important Information