Barriers to Renewable Energy Investment in the Indonesian Power Sector

A thesis submitted for the degree of Doctor of Philosophy

of The Australian National University

Kurnya Roesad

Date: 04/12/2017

Unless otherwise acknowledged in the text, this thesis represents the original research of the author.

Kurnya Roesad

Canberra, 4 December 2017

Acknowledgements

Writing this thesis has been a period of profound learning for me, on an academic and personal level. It goes without saying that I would not have been able to finish this dissertation without the support of many people, and I express my deep gratitude to them here.

First and foremost, I want to thank my panel of academic supervisors at the Crawford School of Public Policy, ANU: Professor Frank Jotzo, Dr Paul Burke, Dr Matthew Dornan and Professor Stephen Howes. Their academic and scientific guidance have been invaluable. Most importantly, their patience in persisting with me gave me the confidence to see through the difficult writing process.

I also want to extend my gratitude to various colleagues at ANU who supported this thesis by taking the time to comment on various aspects of my research, exchange ideas or provide administrative support. They include Associate Professor Dr Budy P. Resosudarmo, Associate Professor Dr Colin Filer, Associate Professor Dr Sango Mahanty, Dr Rachel P. Lorenzen, Dr Patrick Doupe, Dr Megan Poore, Tracy McRae, Alison Francis, and Nurkemala Muliani.

I met with various stakeholders in the Indonesian electricity sector who generously gave time for interviews and access to data. They are listed in the appendices of Chapters 3 and 4 in this thesis. I thank the Australian Leadership Awards for financial support.

During the course of my professional career in Indonesia, various people provided me with guidance and supported my ambition to pursue a PhD: Dr Mari Pangestu, Dr Muhammad Chatib Basri, Dr William Wallace, Bert Hofman and Anna van Paddenburg.

A special thank you goes to my friends and extended family in Canberra who provided me with moral support throughout the years: Marcus Mietzner, Frank Jotzo, Sally White, Amrih Widodo, Inez Nimpuno, Ross McLeod, Prapti McLeod, Indri Sari, Nurkemala Muliani and Ariane Utomo.

In Jakarta, I am especially indebted to my friends who helped me through some difficult periods on a personal level and were much needed good company in enjoying the brighter, especially culinary aspects, of life: Jeremy Wagstaff, Sari Sudarsono, Poppy Barkah, Jim Haggin, Joyce Lim, Rainer Heufers, Felicia Nugroho, Ong Hock Chuan, Maggy Horhoruw, Bhimanto Suwastoyo, Rayya Makarim, Elvie Nasution, Marvin Suwarso and Nesya Hughes Suwarso.

Finally, I thank my family who were always supportive and stood by me: my parents Titien Widayati Roesad and Poernama Roesad, my sister Winny Rachmawaty Roesad, and my brother-in-law Jajang Kurniawan. This thesis is devoted to my parents.

Capstone Editing provided copyediting and proofreading services, according to the guidelines laid out in the university-endorsed national 'Guidelines for Editing Research Theses'.

Abstract

Indonesia has set ambitious targets of increasing the share of renewable energy in electricity supply and reducing greenhouse gas emissions relative to a baseline. But despite abundant renewable energy resources and policies to promote renewable energy, the country has experienced only slow additions in renewable electricity supply. Future expansions in generation capacity are planned to rely heavily on coal-based power supply. This thesis examines the barriers to renewable energy in Indonesia, provides a detailed case study on the effectiveness of specific renewable energy policy instruments in a developing economy context and applies mean variance portfolio (MVP) theory to analyse power supply outcomes.

This thesis provides a historical analysis of the effectiveness of policies to incentivise renewable energy supply in the Indonesian electricity sector. Empirical analysis of supply trends covers the period 1990–2015, while perceptions of the effectiveness of regulatory incentives are based on stakeholder interviews conducted in 2011 and 2012. The main finding is that a combination of regulatory uncertainty in the Indonesian power sector, financial weakness of the national electricity utility Perusahaan Listrik Negara (PLN) and ineffective feed-in tariffs have had a dampening effect on renewable energy investment. In the absence of credible, mandatory renewable energy targets for PLN, the utility has prioritised coal and gas over renewables. An important reason being that renewable power projects carry higher upfront investment costs and, until now, have been more expensive per unit of power output. Feed-in tariffs have been rendered ineffective as they were set at levels too low to act as premium prices, with PLN and independent power producers locked into lengthy negotiations over contracts, thus slowing project implementation.

Taking the long view, the thesis uses MVP theory to analyse the risk-mitigation potential of renewables in PLN's future electricity supply mix. This analysis identifies the cost risk trade-off of various electricity mix scenarios and provides a quantitative measure to assess the potential benefits from diversifying energy production.

The findings are that the average system costs for various future technologies are in a narrow range, with renewables cheaper than conventional generation technologies,

especially when carbon costs are included. The risk of investing in the power sector, defined as cost risk and measured by the standard deviation of past cost streams, differs significantly across generation technologies and is lower for renewables. Energy portfolios containing a large share of renewables combined with energy efficiency measures are now preferable in cost and risk terms, although at higher discount rates the cost advantage is less pronounced.

This thesis concludes that policy reforms need to focus on continuing to move towards cost-reflective tariffs to improve PLN's financial footing. Combined with continued declining costs of renewables, feed-in tariffs could become more effective when set at levels that truly act as premium prices. They could be combined with quantitative instruments such as renewable portfolio standards to help overcome institutional bias against renewables within PLN, especially in a period of transiting towards a cost-effective tariff system and phasing out of subsidies.

Contents

List of Tables

List of Figures

List of Abbreviations

Abbreviation	Indonesian	English
ADB		Asian Development Bank
APBN	Anggaran Pendapatan dan Belanja Nasional	National State Budget
BAPPENAS	Badan Perencanaan dan Pembangunan Nasional	National Planning and Development Agency
BPP	Biaya Pokok Penyediaan Tenaga Listrik	Basic Cost of Electricity Production
BPPT	Badan Pengkajian dan Penerapan Teknologi	Agency for the Assessment and Application of Technology
BANPRES	Bantuan Presiden	Presidential Assistance/Support
BAU	Kondisi saat ini	Business-as-usual
BPK	Badan Pengawas Keuangan	State Audit Agency
BKPM	Badan Koordinasi Penanaman Modal	Indonesia's Investment Coordinating Board
BSP		Bioguna Sustainable Power
CGE		Computable General Equilibrium
CDM		Clean Development Mechanism
CER		Certified Emissions Reductions
CO2	Karbon Dioksida	Carbon Dioxide
COD		commercial operational dates
CSO		civil society organisations
DGEEU		Directorate General for Electricity and Energy Utilization
DME	Desa Mandiri Energi	Village Energy Self Sufficient Programme
DRP	Parliament	
DSCR		debt service coverage ratio
EIA		Energy Information Administration

EPC	Enjinering, Pengadaan dan Konstruksi	engineering, procurement and construction
ERPI		Electricity Power Research Institute
PD	Keputusan Presiden	Presidential Decree
FIT		feed-in tariff
GDP		Gross Domestic Product
GWA		geothermal work area
IEA		International Energy Agency
IBEKA	Institut Bisnis Ekonomi dan Kerakyatan	Institute for People's Business and Economy
IDR	Rupiah Indonesia	Indonesian Rupiah
IPP		Independent Power Producer
IRR		internal rates of returns
IUKU		Electricity Business Licence for Public Provision
IUP	geothermal mining licence	Izin Usaha Pertambanganan Panas Bumi
JICA		Japanese International Cooperation Agency
KfW	Kreditanstalt fuer Wiederaufbau	
km		kilometre
kV		kilovolt
kW		kilowatt
kWh		kilowatt hour
kWp		kilowatt peak
LCOE		levelised electricity costs
MEMR	Kementerian Energi dan Sumber Daya Mineral	Ministry of Energy and Mineral Resources
MoF	Kementerian Keuangan	Ministry of Finance
MoEF		Ministry of Forestry
MoT	Kementerian Perhubungan	Ministry of Transport

MSOE	Kementerian Badan Usaha Milik Negara	Ministry of State-Owned Enterprises
MW	Mega Watt	megawatt
MWh		megawatt hour
METI	Masyarakat Energi Terbarukan Indonesia	Renewable Energy Society Indonesia
MHP		Micro hydro power
MHPP		Mini hydro power project
MR		Ministerial Regulation
MVP		mean variance portfolio
MWp		megawatt peak
NREEC		Directorate General for New and Renewable Energy and Energy Conservation
OM	Manajemen dan Operasional	operations and maintenance
OECD		Organisation for Economic Co-operation and Development
PR	Peraturan Presiden	Presidential Regulation
PERTAMINA	Perusahaan Pertambangan Minyak dan Gas Bumi Negara	National State Oil and Gas Company
PLTA	Pembangkit Listrik Tenaga Air	Hydropower Electricity Generation
PLTS	Pembangkit Listrik Tenaga Surya	Solar Power Generation
PLN	Perusahaan Listrik Negara	National Electricity Company
PNPM	Program Nasional Pemberdayaan Masyarakat	National Community Empowerment Program
POME		Palm Oil Mill Effluent
PP	Peraturan Pemerintah	Government Regulation
PPP		public private partnerships
PSO		Public Service Obligation
PV		photovoltaic
principal–agent		PA

RE		renewable energy
MoHA		Ministry of Home Affairs
RES		Renewable Electricity Standards (RES)
RET		Renewable Energy Target
RPS		renewable portfolio standard
REDD		Reducing Emissions from Deforestation and Forest Degradation
RUEN	National Energy Plan	Rencana Umum Energi Nasional
RUPTL	Rencana Usaha PenyediaanTenaga Listrik	National Electricity Supply Plan
SAIDI		system average interruption index
SAIFI		system average frequency index
SBC	soft budget constraint	
SHS		solar home system
SKE	Selo Kencana Energi	
SMP		small power producer
SMPP		Small and Medium Power Producers
SMHPP		Small and Medium Hydro Power Project
SOE	Badan Usaha Milik Negara	State-Owned Enterprise
SR		strong renewables
SULO	Sertfikat Uji Layak Operasi	Commissioning Certificate
TDL	Tarif Dasar Listrik	Basic Electricity Tariff
UNEP		United Nations Development Programme
UNFCCC		United Nations Framework Convention on Climate Change
US		United States
UPL	Upaya Pengelolaan Lingkungan	Environmental Management Effort Document

US$/USD		United States Dollar
UU	Undang-undang	Law
VG		Viability Guarantee
VAT		Value-Added Tax
VIM		Vertically Integrated Monopoly
VSPP		Very small power producer
WR		weak renewables
WTE		Waste to Energy

Chapter 1: Introduction

1.1 Research question

The global renewable energy (RE) industry has experienced remarkable growth since the mid-2000s. Total global capacity of many renewable technologies have seen average annual growth rates of between 15–50 per cent since 2005 (REN21 2011, 2016). By 2040, the International Energy Agency (IEA) predicts that 60 per cent of all new power generation capacity will come from renewables and that the majority of renewable technologies will be competitive without subsidies (IEA 2016).

In 2015, global investment in RE increased to US$285.9 billion, a 5 per cent increase compared to 2014. This exceeded the last record in 2011, which stood at US$278.5 billion (REN21 2016, p. 18). Annual addition of RE capacity now exceeds additions of all fossil fuel capacity combined. Wind and solar power accounts for 77 per cent of new installations, and by the end of 2015 RE could supply an estimated 23 per cent of global electricity (REN21 2016, p. 18).

By 2016, 173 countries had set policy targets and legislated policies to foster renewables (REN21 2016, p. 19). Feed-in tariffs and renewable portfolio standards (RPSs) or quotas are the most popular policy instruments. Feed-in tariffs are widely used, with 110 countries, states and provinces reported to have implemented them by 2016. Quotas were in place in 100 states, provinces or countries (REN21 2016, p. 19).

So far, however, the growth in RE capacity has been mainly concentrated in advanced Western economies and large emerging economies such as China. In 2015, global RE generation capacity stood at 1,849 GW, with 746 GW (42 per cent) located in developing economies. China accounted for 27 per cent (496 GW) of the global total and India boasts the second-largest share (4 per cent or 83 GW) in renewable generation capacity, with the remaining emerging economies sharing the reminder (REN21 2016, p. 141).

This uneven deployment of renewable generation capacity within the group of emerging economies indicates that the effectiveness of RE policies varies across countries. To date, the literature on RE policies has largely focused on advanced economies and has paid little attention to the state of the energy sector in developing countries, including Indonesia. The focus on the developing world is important, as the IEA projects that global energy demand will increase by 30 per cent between 2016 and 2040, assuming a declining energy demand by Organisation for Economic Co-operation and Development (OECD) countries and a shift of energy consumption to industrialising and urbanising India, Southeast Asia and China and parts of Africa, Latin America and the Middle East (IEA 2016). Whether and how the policy conditions underlying the energy sector, and especially the electricity sector, can undermine RE policies in a developing country context is the general question with which this thesis is concerned.

Indonesia represents an interesting case study for various reasons. First, it represents a large emerging economy similar to China and India and is richly endowed with both fossil fuel–based and RE resources. Second, policymakers in Indonesia have been putting in place policies to promote renewables since the 1990s. Specifically, since 1995, the government has provided a legal framework for investment in the geothermal sector. Centrally planned generation expansion targets have also been used to promote geothermal generation. The Indonesian Government has also used feed-in tariffs (FITs) to encourage the take up by state utility, Perusahaan Listrik Negara (PLN), of renewable power supplied by small and medium-sized producers. Third, despite these policies, the country's record of increasing the share of renewables in the broader generation mix has been poor and it continues to rely heavily on the expansion of fossil fuel–based power generation such as coal, as outlined in its most recent planning documents.

This leads to the central research questions of this thesis: Why, despite the existence of abundant RE resources and the policies to promote them, has Indonesia experienced only slow growth in renewable electricity supply? Why have Indonesia's RE policies not worked well? What does this teach us about the interaction of renewable policies and institutions in developing countries? What are the implications for the promotion of RE policy in developing countries more broadly? These questions are particularly poignant, as large emerging economies such as China and India are investing heavily in renewables, while Indonesia is in danger of being locked in to coal-fired power generation for decades to come.

1.2 Literature review

This thesis draws on several separate sets of literature and attempts to have them 'speak' to each other. One is the literature on policy instruments for promoting RE. The second is on the market structure of the energy and electricity sector in developing countries. The third consists of mostly policy-oriented studies and reports assessing Indonesia's energy and RE policies. The fourth deals with assessing the risk of investing in power generation technologies, particularly in regard to long-term energy planning. These strands of literature are summarised separately below, and then brought together to identify research gaps.

1.2.1 Policy instruments to promote renewable energy

Policy instruments to promote RE can be grouped into three broad categories (World Bank 2011c, p. xiii; REN21 2011, p. 52). Table 1 shows that they can be based on *fiscal incentives* (e.g., tax policies, rebates and grants), *public finance mechanisms* (e.g., loans and guarantees) and *regulations* (e.g., FITs, quotas, biofuels and blending mandates) (IPCC 2011, p. 871; REN21 2011, pp. 52–53).

RE policy instruments promote of a certain class of generation technology (World Bank 2011c). RE policy instruments can be seen as substitutes or second-best policy options for carbon pricing instruments such as carbon taxes or emission trading, especially as in many countries where resistance to carbon pricing is still strong (World Bank 2011c, p. ix; Labandeira & Linares, p. 2010).

Table 1.1: Technology-based renewable energy policy instruments

Fiscal incentives	Regulatory		Public investment/finance
	Price-based	Quantity-based	
Demonstration grants	Feed-in tariffs	RPS (renewable energy portfolio standards) quotas	Government investment in venture capital
Public R&D	Net metering	Electricity utility obligation	Public investment vehicles
Investment subsidies		Renewable energy certificate trading	Loans, grants
Preferential tax treatment			Public procurement
Subsidies for energy efficiency purchases			Guarantees
Tax credits			

Source: REN21 (2011), IPCC (2011) and World Bank (2011c).

Fiscal incentives aim to reduce the costs and risks of investing in RE. This can be achieved by lowering upfront investment costs, directly reducing the production cost or increasing the payment to RE producers (IPCC 2011).

The experience with fiscal policy instruments suggests that they are mostly effective when applied in a complementary fashion and in combination with other policy mechanisms (IPCC 2011, p. 892). For example, most successful programs to promote solar, wind and biogas power rely on a combination of rebates with net metering, public education and low-interest loans. Tax credits for renewable investment have been effective in countries where there is a solid base of tax-paying private sector firms (IPCC 2011, p. 892).

Public finance mechanisms include instruments like public investment into private equity, guarantees, loans (debt financing usually via soft loans) and public procurement of RE technologies. Governments use these instruments to either directly leverage commercial investment into RE projects or indirectly help create commercially sustainable markets for these technologies. Public finance mechanisms are commonly used in developing countries, where the domestic financial sector is still weak and risk averse to RE projects (IPCC 2011, p. 893).

An assessment of the role of public finance mechanisms for renewables development was provided by IPCC (2011). In emerging economies, loans provided by international development agencies and financing institutions play a major role in boosting public finance mechanisms that support renewables. They either directly fund RE projects or fund the development of institutional frameworks conducive for RE investments.

Generally, credit lines are preferred instruments, because they help build local capacities for RE financing. One successful example is the credit loan that the Indian Renewable Energy Development Agency received from the Kreditanstalt fuer Wiederaufbau banking group (KfW), World Bank and Asian Development Bank (ADB) for lending to the domestic RE sector (IPCC 2011, p. 893).

The advantage of a public loan at concessional rates or a 'soft loan' is that it is relatively easy to administer. Soft loans have been used prominently in Germany, Spain, Japan, Sweden and Norway to support RE technologies. Public loans can also be used to buy down the interest rate while a commercial financial institution provides most of the project financing. Examples from emerging economies include India and Tunisia for solar thermal and photovoltaic (PV) financing (IPCC 2011, p. 893).

Guarantees and public procurement mechanisms have also been increasingly used as instruments to promote renewables. Guarantees have been useful in sharing credit risk in RE projects and help domestic banks in gaining experience in managing portfolios containing RE loans and develop adequate risk assessment procedures to assess projects. Public procurement of RE technologies, particularly using tender or reverse auction mechanisms, has become more important in recent years. By the end of 2015, 64 countries had held tenders for RE, with many reporting record bids in terms of low prices and high volumes (REN21 2016, p. 20).

One challenge is the uncertainty surrounding the viability of the international carbon finance framework under the Kyoto Protocol's Clean Development Mechanism (CDM) (Aldy & Stevens 2007; Victor 2011). Since the end of the Kyoto Protocol in 2012, uncertainties about the CDM and resulting fluctuations of Certified Emissions

Reductions (CER) prices in global carbon markets have affected the viability of many RE projects. The CDM has been criticised for the issuance of carbon credits for projects that were not really 'additional' in their investment and reduction in emissions (Victor 2011, p. 94). Meetings of the Conference of the Parties (under the United Nations Framework Convention on Climate Change (UNFCCC) and the emergence of the Paris Climate Agreement in 2016 have intensified efforts to harmonise the various international climate financing mechanisms, including the CDM, under a Green Climate Fund (REN21 2016).

New public investment vehicles increasingly play an important role. For example, a new phenomenon is the leveraging of private investment by using public funds administered and delivered by international finance institutions. As an example, public private partnerships (PPPs) represent this type of investment vehicle and have become more popular in recent years to fund large infrastructure and power generation projects (IPCC 2011, p. 894; Strategic Asia 2012).

Regulatory policy instruments are the most commonly used policy instrument to promote RE-based electricity. Generally speaking, there are two approaches, quantity-based and price-based policies. Within a developing country context, the former is still rarely applied, while the latter, especially in the form of FITs, is applied in more than 100 countries (REN21 2016).

Quantity-based instruments include quota obligations under which governments mandate utilities to obtain a minimum share of generation capacity coming from RE (IPCC 2011, p. 895). They can be linked to green certificate trading. Notable examples for quota-based schemes can be mainly found in advanced economies like the United States (US), Norway, Sweden, the United Kingdom, Australia and Canada. The literature cites only one example from an emerging economy, the Indian Renewable Electricity Standards (RES), mandating utilities to increase their obligations by 0.5–10 per cent of their total electricity portfolios, depending on the state. However, in 2009, only 14 of 28 states issued regulations or orders in that regard (Mendoncanam Jacobs & Sovacol 2009, p. 107).

The main insights on the effectiveness of quota-based RE instruments for the electricity sector can be summarised as follows (IPCC 2011, p. 896). They work best if applied to a large segment of the market. Quotas need to be based on clear eligibility rules in regard to participants and resources. Quotas should exceed existing supply but be achievable at reasonable cost. Long-term purchasing obligation contracts without interruptions between new and old quotas are important. An important criterion is that adequate penalties and their enforcement are applied. Long-term targets need to be announced and technology-specific bands issued. (IPCC 2011, pp. 896–897).

The most popular RE instrument is the price-based *FIT*. A basic FIT pays a guaranteed price for power generated from a RE source, most commonly for each unit of electricity that is fed into the grid by a producer (REN21 2011, p. 56). FITs can set a fixed price that is independent of electricity market prices and ideally provide fixed premiums on top of market prices for electricity (IPCC 2011, p. 899). FITs were first applied in Europe and the US in the early 1990s. Thus, much of the literature is based on the experience of advanced economies (IPCC 2011; REN21 2011; Mendoncana, Jacobs & Sovacol 2009).

The literature on the experience of FITs in the developing world is limited to a few countries. In 2008, Kenya introduced FIT legislation aimed largely at biomass, small-scale hydropower and wind. South Africa introduced a FIT scheme in 2009 to promote generation by landfill gas, small hydro (less than 10 MW), wind power and concentrating solar power (Mendoncana, Jacobs & Sovacol 2009, p. 102).

In Asia, several developing economies have started FIT programs (Sovacol 2010). China has introduced a FIT for wind power and for utility-scale solar plants in 2009. India has introduced FITs for solar power generation in several states, notably West Bengal, Rajasthan, Gujarat and Punjab (Mendoncana, Jacobs & Sovacol 2009, pp. 107–108). Malaysia aims to meet a RE target of 3,000 MW by 2020 and introduced FITs aimed mainly at solar PV and bioenergy (REN21 2011, p. 55). Thailand is regarded as a good example for the integration of a FIT scheme into an already well-designed, sequenced and effective RE policy aimed at increasing supply from biomass and solar producers (IPCC 2011, p. 902).

The literature suggests fiscal, regulatory and public investment types of instruments complement each other and coexist to achieve RE targets. Moreover, the design and implementation of policy instruments very rarely happens under perfect market conditions. In general, many policy distortions exist in domestic energy markets—taxes, information asymmetries, knowledge spillovers, bounded rationality, network externalities, government failures and so on. Thus, second-best policies are required to address multiple market failures and a combination of policy instruments is a more adequate and realistic prescription, rather than relying on one instrument alone to achieve specific climate policy targets (Labandeira & Linares 2010).

FITs, for example, may require both regulatory and fiscal actions. This can happen in the form of a fiscal incentive like capital subsidies to fund high upfront costs, which are typical in the geothermal sector. Or they can be designed through state budget support or special funds to subsidise FITs (Mendoncana, Jacobs & Sovacol 2009; Castlerock 2011). In short, there are no one-size-fits-all prescriptions in the application of RE policy instruments, and their design needs to take account of the specific domestic fiscal policy mixtures and regulatory settings in the electricity sector.

1.2.2 Electricity sector reforms and renewable energy policies

Much of the effectiveness of RE policies must be seen within the broader context of electricity sector reforms and the overall development stage of a country. However, while there is a lot of academic literature that looks at the impact of electricity sector reforms in developing countries, not many case studies see RE policies within the context of broader electricity sector reforms. In the following sections, the major issues linking both sets of literatures will be discussed.

Governance and political economy factors in the electricity sector frequently prevent effective cost pass-through mechanisms, which is typically the case in many Asian countries with vertically integrated monopolies (VIMs) (World Bank 2011c). Typical features of the energy sector in developing countries include state dominance of the electricity sector; financially constrained utilities; strong growth of highly price-inelastic electricity demand; and significant losses in distribution and transmission, resulting in undersupply and shortages (World Bank 2011c; Dethier & Straub 2011, p. 13).

Governance problems frequently exist in sectors where utilities are regulated by public service obligations (PSOs) or universal service obligations (USOs) (Estache & Wren-Lewis 2009). Under PSO arrangements, as is the case in Indonesia’s electricity sector, pricing policies are frequently used to achieve not only allocative efficiency but redistributive goals. But these pricing policies are often ineffective, as asymmetric information problems can undermine regulatory effectiveness (Laffont 2001).

Using the example of a monopolistic firm investing in the expansion of telecommunications network in rural areas, Estache and Wren-Lewis (2009) show that asymmetric information induces a higher price and smaller network expansion compared to situations with complete information. This happens because there is always an incentive for collusion between the regulator and the monopolistic firm: a monopolistic firm always obtains an 'information rent' by not disclosing its marginal cost of providing services. Thus, the firm has an interest to collude with the regulator in the sense that its private information is not disclosed by the latter. This is especially true if the firm has a low-cost technology to produce its services. It can be argued that energy subsidy arrangements under a PSO regime between governments and utilities are also vulnerable to principal–agent (PA) and asymmetric information problems. These can enhance uncertainties in the cost and pricing of electricity supply and potentially bias investment and capital cost structures in favour of cheaper, non-renewable fuel generation technologies (Beaton & Lontoh 2010; World Bank 2007).

1.2.3 Renewable energy policy in Indonesia

The Indonesian literature on the role and impact of RE policy instruments has been the subject of several academic papers, review-type policy reports and some technical studies. The role of domestic fiscal policy instruments for climate mitigation and adaptation was surveyed by Resosudarmo and Abdurohman (2011). The authors reviewed Indonesia's fiscal policy regime for mitigating the two main sources of CO2 emissions, namely deforestation and the energy sector. In the forestry sector, a mixture of user charges and natural resource extraction fees has been in place since the 1970s. In the energy sector, fuel taxes have been in place since the 1980s. However, the continued use of fuel subsidies has undermined the effectiveness of the tax and runs contrary to environmentally friendly outcomes.

Resosudarmo and Abdurohman (2011) found that the Indonesian Government has long used revenue instruments to influence resource extraction but had only limited impact in steering economic actors to environmentally sustainable behaviour. The main reason for this is that the focus of the policymakers has always been to raise revenue, rather than targeting an optimal rate of resource extraction. Additionally, there is a high rate of illegal extraction activities, particularly in the forestry sector. Higher tax rates would result in even less compliance rates and increased illegal extraction activities (Resosudarmo & Abdurohman 2011, p. 10).

The authors also argue that the long-term prospects of successfully implementing green fiscal policy instruments remains uncertain. The central policy proposals are centred on a carbon tax, fuel excise and the gradual elimination of fuel and electricity subsidies in the energy sector, and incentives for regional governments to implement Reducing Emissions from Deforestation and Forest Degradation (REDD) activities. However, in the 2000s, resistance to energy subsidy reductions was strong, and concerns about the loss of jobs in the natural resource sectors were dominant. Moreover, the government embarked on an expansion of coal-fired electricity in the Fast Track electricity program which countered fiscal efforts to mitigate emissions from the energy sector (Resosudarmo & Abdurohman 2011, p. 10).

Resosudarmo and Abdurohman (2011) provides a useful overview of the government's use of fiscal instruments to support environmental objectives. However, it does not undertake a detailed analysis of the use of specific fiscal policies that encourage RE investment in the energy sector. The analysis is confined to an observation of general revenue and expenditure trends in sectors related to the environment.

The Ministry of Finance (MoF) (2009), in its Green Paper and the World Bank's Low Carbon Development Options Project (summarised in Mubariq 2010), have commissioned Computable General Equilibrium (CGE) studies to simulate the macroeconomic effects of a carbon tax on the Indonesian economy. The main result of these studies is that a carbon tax could achieve both economic growth and reduction of CO2 emissions, if the revenues are recycled to reduce other taxes (such as sales taxes) and provide non-distortive poverty alleviation schemes such as cash transfers to poor households.[1]

---

[1] The MoF's (2009) Green Paper modelled a carbon tax of IDR 80,000 per ton of CO2 and estimated that it would reduce emissions from fossil fuel combustion by about 10% relative to business as usual. Additional emissions reductions were believed to be able to be achieved through specific sectoral policies such as policies to support geothermal power or selling of carbon permit exports, potentially earning exports revenues in the order of US$2–3 billion per year until 2020 (MoF 2009). It was assumed that the tax would be fully passed through to consumers of fuel and electricity subsidies. The studies under the World Bank's Low Carbon Development Project emphasised REDD

The recommendations of the MoF's (2009) *Green Paper* affecting the electricity sector focused on institutional mechanisms to strengthen coordination in two areas. First, it was recommended to install a formal unit devoted to climate change fiscal policies at the Echelon II level. Second, introduction of a carbon/fossil fuel tax in parallel with a gradual reduction of the fuel and electricity subsidies (MoF 2009). Specifically, the MoF, in collaboration with the Ministry of Energy and Mineral Resources (MEMR), launched a Roadmap of Fuel and Electricity Subsidy Reduction and has succeeded in gradually implementing those reforms—since 2013, electricity tariffs have increased substantially and subsidies for some consumer categories have been abolished (Burke & Kurniawati 2018). Third, the MoF will oversee policies to accelerate RE development in Indonesia, specifically in the geothermal sector. As a first step, the MoF pushed through a revolving fund in the 2011 budget to help geothermal investors with funding activities in the exploration stage (MoF 2009).

A major difference between the MoF's (2009) study and the CGE studies commissioned by the World Bank is that the latter looked at policy simulations to increase energy efficiency in the electricity and the manufacturing sectors. In the power sector, the CGE studies under the World Bank's Low Carbon Development Project found that lowering carbon intensity in the electricity sector can yield positive results not only in terms of emissions but in poverty reduction. The studies assumed that technology transfers from abroad are funded by the government budget. The study assumes a 20 per cent increase in fuel efficiency in the electricity sector but does not specify which fuel mix choices are used to achieve those efficiency improvements (Mubariq 2010).

The academic modelling work underlying the MoF's (2009) *Green Paper* and the World Bank's Low Carbon Development Options Project shows that low carbon growth outcomes can be achieved by mixing fiscal instruments with technology-based policies. The former includes carbon taxes and reduction in energy subsidies. The latter includes investment in technologies to increase energy efficiency in the power and manufacturing sectors. However, none of these studies have concretely modelled

---

and scenarios with different carbon prices. The best outcomes in terms of Indonesia receiving revenues from REDD using a price of US$20/ton of CO2 equivalent. This assumes certain income distribution proportions between government and households, taking account of rural urban and Java and non-Java households. Although there is a slightly slower national growth, growth is positive in several regions, indicating positive distributional income flows from the centre to the regions (Resosudarmo & Abdurohman 2011).

specific RE policy instruments such as FITs or RPS and the like and their financial implications for the power sector and the state budget.

General assessments on the role of RE policies in Indonesia's electricity sector were conducted by two major policy studies (USAID 2009; IEA 2009). USAID's (2009) *Indonesia Energy Assessment* identified policy and regulatory barriers as the most significant barriers to scaling up RE investment. These include fuel subsidies which undercut the viability of non-fossil fuel–based projects. Further, the national electricity tariffs are not high enough to cover PLN's production costs. Additionally, a lack of policy coordination among various electrification programs and enforcement of regulations contributes to low investment in the sector. Lastly, a lack of fiscal incentives for new technology and RE utilisation plays a significant role in hampering the development of clean energy projects (USAID 2009, p. 10).

The IEA (2009) also conducted a comprehensive policy study on the Indonesian energy sector. Similar to USAID's (2009) study, the report recommends the need for electricity tariff reform to ensure cost-reflective pricing to allow Independent Power Producers (IPPs) to earn sufficient and predictable investment returns. It emphasised that the financial needs to support RE projects depend on transparent information on the production costs of electricity, which are not readily available. Hence, there are difficult and protracted power purchase agreement (PPA) negotiations between the utility and IPPs until both parties can be assured of obtaining sufficient returns to investment (IEA 2009, p. 103).

The IEA's (2009) most important policy recommendation affecting the RE sector was the need to establish an independent agency and the use of FITs. An independent agency should review and determine electricity prices. Initially, its primary task would be formulating the policy of transiting towards a cost-reflective electricity tariff system. This independent agency would also be asked to determine the level of FITs at which PLN would be obliged to take up renewable electricity. The report argues that a FIT system would be preferable to other RE policy instruments such as RPSs or quota obligations, because it would ensure greater investor certainty and would also be more suitable to promote RE from small and medium producers (IEA 2009, p. 103).

While the IEA (2009) and USAID (2009) provided detailed review reports on the role of RE policies in Indonesia's energy sector, they are short on technical analysis on the viability of RE policy instruments options for Indonesia. Moreover, while the analysis in both reports stresses the importance of institutional, regulatory and legal arrangements in the energy sector, there is no detailed account of the political economy factors that shape policy outcomes in the energy sector. Finally, both reports identify the inadequate tariff structure as a main constraint to RE development. However, there is no clear analysis on the relationship between basic electricity tariff (tarif dasar listrik (TDL)) and PLN's underlying generation costs (BPP) and the underlying cost concepts involved.

The most comprehensive studies on the viability of RE policy instruments are on the Indonesian geothermal sector. The Japanese International Cooperation Agency (JICA) (2009) and Castlerock (2011) conducted detailed technical studies to provide an economic evaluation of geothermal investment, particularly in comparison to coal-fired electricity. Both studies concluded that the differences in costs and the selling price still favour coal-fired power generation and that, without government support, geothermal investment is in many cases too risky for most developers. Both studies concluded that FITs are the most viable instruments to promote geothermal development but need to be backed by either a combination of FITs and corporate tax income reduction for developers (JICA 2009) or increased PSO subsidy or tariffs (Castlerock 2011).

Both geothermal studies by JICA (2009) and Castlerock (2011) are detailed in their technical analysis on the economic feasibility of geothermal investment. However, given that they are government-sponsored technical and sector-specific studies, they do not provide the 'big picture' on the role of RE policies in Indonesia's overall energy context. Specifically, they do not undertake any analysis on the historical and institutional settings of the electricity sector in which geothermal investment could take place.

1.2.4 Electricity sector reforms in Indonesia

McCawley (1970, 1978) was the first to give comprehensive academic accounts of the pricing problem in Indonesia's electricity sector and its effects on electrification programs. The author essentially found that since the 1960s the electricity sector relied on the practice of energy price suppression and hidden subsidies. Rural electrification schemes were particularly affected, as they relied heavily on external donor funds, but were poorly administered (McCawley 1978). Kristov (1995) picked up on McCawley's work and provided a quantitative assessment of hidden subsidies in PLN's finances and found that the average retail price per kWh should have been 46 per cent higher in 1980–1994 than stated in PLN's official accounts.

In 2005, the World Bank published the report *Electricity for all: options for increasing access in Indonesia* (World Bank 2005). The study was conducted in collaboration with the MEMR and PLN. It was based mainly on interviews with policymakers in selected provinces in Batam, South Sumatra, West Nusa Tenggara and East Kalimantan. The study aimed to provide feasible and innovative policy options to enhance rural electrification, especially in the aftermath of the decision of the Supreme Court to annul a new Electricity Law in 2004, which would have substantially liberalised the electricity sector.

From the perspective of addressing links between electricity sector reforms and the viability of RE options, the report identified three main policy barriers. First, the absence of cost-recovering tariffs in the mid-2000s prevented Indonesia's national power provider, PLN, with sufficient revenue for achieving long-term financial sustainability. The TDL is a tariff structure applied only to PLN and charged irrespective of the varying costs associated with providing electricity to different regions of the country. Faced with revenue shortfalls, PLN has focused on loss minimisation as opposed to access maximisation (World Bank 2005). Second, there was a lack of government leadership, political commitment and coordination in governing the electricity sector. This has been compounded by the insufficient legal framework, which was ambiguous about the role of non-PLN providers, particularly in regard to the process of allocating electricity supply permits and licenses. Third, as a result of the previous two factors, there has been a lack of access to sustainable financing sources for rural electrification projects, especially RE ones.

These three barriers have resulted in conditions that have allowed PLN and private developers to experiment with RE on only a small-scale basis and using unfamiliar investment vehicles. In regions outside the Java–Madura–Bali grid, several projects have used small-scale renewable power supply schemes, such as PV or micro hydro systems. However, in many cases, these projects are unsustainable because of significantly higher unit costs due to a lack of economies of scale. Further, even in projects for which private financing is available, this typically is associated with large amounts of collateral. In many cases, investors are unable to meet demands of banks to put up sufficient collateral (World Bank 2005).

Wells and Ahmed (2007) provided the most detailed account of the first IPP program launched in the 1990s. Most of these projects, which included geothermal IPPs, were postponed and restructured in the wake of the Asian Financial Crisis of 1998. The authors argue that the failure to implement those projects was not rooted in the legal framework but was due to a mixture of political factors and capacity problems on the side of the Indonesian bureaucracy. Domestic policymakers, especially on the side of PLN, were not equipped with the information and data necessary to deal with complex negotiations with foreign-led IPPs. These problems were compounded by the prevailing political economy structure under the New Order regime, in which foreign investors colluded with the personal interests of highly placed individuals. As a result, PPAs were unfavourable to PLN, as they produced high electricity purchasing prices and an imbalanced allocation of risks and rewards (Wells & Ahmed 2007).

Seymour and Sari (2002) and Purra (2009) provide an institutional and political economy analysis of the Indonesian electricity sector. The former provided a report which detailed the political forces shaping the liberalisation efforts in the electricity sector from 1998–2002. They argued that the root cause of the slow reform process lies in the political battle on the constitutionality of liberalisation efforts in the electricity sector. As the constitution cements the government (via PLN) as the single provider of electricity, liberalisation efforts in the power sector were generally perceived as lacking a firm legal mandate and favour the Suharto-allied conglomerates and their foreign allies. This is a fundamental source of legal uncertainty which has continued to plague investment up to the present (Seymour & Sari 2002).

Purra (2009) argues that liberalisation in the Indonesian electricity sector has largely failed because the government and the political mainstream is either unwilling or incapable of imposing reforms. Purra (2009) emphasises that the policymaking processes in the sector are fragmented and subject to a complex set of relationships and interests between government agencies. This complex structure makes the administrative process conducive to political manipulation and subject to interagency disputes, benefitting PLN’s interest in maintaining its monopoly (Purra 2009).

1.2.5 Risk-based analysis of investment in the electricity sector

The rapid increase of global investment in renewables has forced utilities to reassess the risks and uncertainties associated with both fossil fuels and renewable generation technologies. Renewable technologies are generally considered to have lower risk profiles than conventional technologies, as they are insulated from swings in fossil fuel prices. Nevertheless, renewables are exposed to other technological, financial, economic and regulatory risks, which vary across technology, country and policy regimes (Ioannou, Angus & Brennan 2017). Solar and wind power, for example, are limited by their intermittency. As Indonesian energy planners seek to increase the role of renewables in future generation mix scenarios, more attention needs to be paid to applying methodologies that adequately assess risks associated with particular technologies.

Mean variance portfolio (MVP) analysis is an established method to analyse the effects of diversifying the energy mix, seen as a portfolio of individual generation technologies that the utility holds, in a way that optimally balances risks and returns of the whole energy portfolio (Ioannou, Angus & Brennan 2017). Few studies have used MVP analysis in Asian emerging economies. In the case of Japan, MVP has been applied to argue for basing investment decisions on electricity supply portfolio risk minimisation instead of cost (Bhattacharya 2012).

MVP is particularly relevant for the Indonesian context, as financial risks (defined as variations in investment returns) play a significant role in the power sector (Ioannou, Angus & Brennan 2017) and PLN has a clear aversion to investing more into renewables. MVP theory provides a good framework to adequately assess risks associated with power generated from fossil fuels and renewables and the overall risks associated with choosing a certain energy mix.

1.3 Limitations and research gaps in the literature

The review of the literature reveals several limitations and research gaps that this PhD thesis addresses. First, there is limited academic work that provides a long-term historical analysis of the effectiveness of policies to incentivise RE supply in the Indonesian electricity sector. Much of the existing literature is dominated by policy review reports and specific technical studies on the geothermal sector. Specifically, no literature has reviewed the role of RE policy instruments in affecting Indonesia's electricity supply mix outcomes.

Second, given the importance of FITs in the literature, the absence of an Indonesian case study is noticeable. Indonesia has had price-based regulations since the mid-1990s, but the literature review on FITs suggests that several institutional requirements to make them work do not exist in Indonesia. Specifically, there is no systematic account of the relationship between PLN's position as a monopsony (i.e., a single buyer of all electricity from IPPs on the national grids) and renewable investment and supply outcomes. The relationship between the financial conditions of the utility—mainly determined by electricity tariffs and subsidies—and the effectiveness of RE policy instruments like FITs has not been documented in detail for the Indonesian case.

Third, given that policy and regulatory barriers play a significant role in Indonesia's electricity sector, and that the utility PLN barely invests in RE, only limited literature exists that systematically assesses investment and financial risk of individual technologies and calculates the benefits of diversifying Indonesia's electricity supply mix. Ver few studies have applied risk-based methods for long-term energy planning in Indonesia. The thesis will address this gap by applying MVP analysis in Indonesia's long-term electricity supply mix scenarios.

1.4 Methodology and thesis structure

The research question and the associated themes outlined in Sections 1.1 and 1.2 are explored in eight chapters.

Chapter 2 analyses renewable programs and policies affecting supply mix outcomes. It relies mainly on descriptive statistical analysis. Specifically, it will use PLN's series of annual data on generation capacity to analyse electricity supply mix outcomes and the share of renewables in it. Secondary literature collected during the fieldwork, mostly in the form of policy studies, reports and official presentations from the government and the private sector, complements the analysis.

Chapters 3 and 4 do look at the historical evolution of FIT regulations for small and medium power producers (SMPPs) and geothermal IPPs. The analysis shows the perceptions of stakeholders on how the interaction between governance factors and pricing policies (primarily FITs) influences investment outcomes in two sectors. These chapters rely heavily on semi-structured interviews with policymakers at various levels of the government, independent experts, industry representatives and IPPs. These interviews were conducted from 2011–2012 and were aimed at identifying the main investment barriers to project implementation in the RE sector.

Chapter 5 puts RE policies in the broader governance context of the electricity sector and provides an historical analysis of the electricity pricing/subsidy process and its impact on PLN's finances. It provides an analysis of how PLN's financial conditions affect the cost of supply of renewables in the electricity sector. Specifically, the utility's financial constraint is a major disincentive to invest in renewables, as coal and gas provide cheaper alternatives on a least-cost or standalone cost basis.

Chapters 6 and 7 deal with the question of how to adequately compare investment risk between fossil fuel–based and renewables technologies.

Chapter 6 provides a definition of risk, allowing for a comprehensive comparison of individual generation technologies. Risk, defined as cost risk and measured by standard deviations of past cost streams, is discussed within MVP theory, which provides a framework to quantify the benefits of diversifying the energy mix by showing the trade-off between levelised generation costs and risks. This chapter calculates levelised electricity costs (LCOEs) and cost risks associated with generation technologies in Indonesia.

Chapter 7 is forward looking and applies MVP to analyse the risk-mitigation potential of renewables in PLN's long-term electricity generation mix. MVP analysis shows the cost risk trade-off of various electricity mix scenarios and provides a quantitative measure to assess the potential benefits from diversifying energy production.

Chapter 8 concludes that policy reforms need to focus on moving towards cost-reflective tariffs to improve PLN’s financial footing, while designing more effective renewables take up instruments that go beyond FITs. These could include policies that include binding RE targets for PLN and price instruments like FITs.

Chapter 2: Renewable Energy and the Supply Mix in the Indonesian Power Sector

Abstract

This chapter analyses the main features of the Indonesian electricity sector and the historical trends that brought about the marginal role of renewables in energy policy. Analysis of the utility's electricity supply trends over the period 1990–2015 shows a significant increase of the role of coal and a decline of renewables in the generation mix. While coal- and gas-fired projects have been largely implemented, realisation of RE investment has been plagued by delays and uncertainties. Indonesia's energy path and supply mix suggests that the prominent rise of coal and the stunted development of renewables is due to an 'endowment effect', as the availability of large coal reserves slows down incentives to diversify the energy sources. Thus, Indonesia's energy path is in danger of being locked in to coal in the coming decades, despite the existence of ample resources of renewables and programs to promote them.

2.1 Introduction

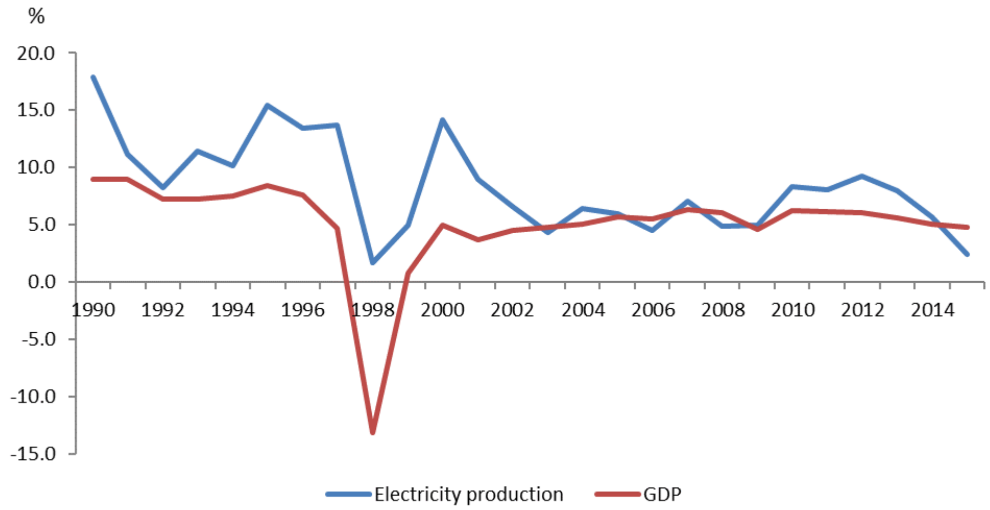
The objective of this chapter is to analyse the main features of the Indonesian electricity sector and the historical trends that brought about the marginal role of renewables in energy policy. It specifically looks at electricity supply mix trends in the period of 1990–2015 and describes the various programs to expand total electricity generation and specific programs to promote RE. Thus, this chapter contributes to the literature by providing a historical analysis of RE trends in the Indonesian power sector.

This chapter begins with a description of the state of the Indonesian electricity sector in Section 2.2 to provide context. Section 2.3 gives an aggregate analysis, while Sections 2.4 and 2.5 focus on the role of PLN, IPPs, and small and medium-scale RE programs. Section 2.6 assesses the energy supply outcomes in the electricity sector in terms of Indonesia's resource endowment and the carbon-intensive nature of power generation. Section 2.7 concludes the chapter.

2.2 General features of Indonesia's electricity sector

RE development must be analysed as part of the Indonesian electricity sector, which has experienced uneven growth in investment and faces significant challenges to meet electrification targets and reduce power shortages. Growth in Indonesia's electricity production has generally followed the trends of GDP. Before the Asian crisis of the late 1990s, GDP growth averaged 8 per cent per annum in 1990–1997 (see Figure 2.1). The crisis of 1998–1999 brought a severe dip in the growth rate to –13 per cent. In the subsequent recovery period from 1999–2005, GDP growth recovered to an average of 4.3 per cent per annum before approaching an average of six per cent per annum in 2006–2015. Electricity production followed a similar pattern, enjoying higher growth rates in the periods before the crisis and after the recovery. It is noticeable that growth in energy production fell from 9.2 per cent per annum in 2012 to 2.4 per cent in 2015, which can be partly attributed to the energy subsidy reform launched by the government in 2013 (Burke & Kurniawati 2018).

Figure 2.1: GDP and electricity production 1990–2015 (%)



Source: Annual PLN Statistics (various issues) and own calculations.

Despite electricity growth being in line with GDP growth, power shortages remain a significant problem for the Indonesian economy. Captive power, which is the share of self-generation by industry in total installed capacity, is an indicator for the unreliability of grid-connected electricity supply. This rate was high in the early 2000s but has decreased in recent years. According to official annual PLN figures, in 2002 captive power stood at 22 per cent of total installed generation capacity at around 6,000 MW. By 2015, the rate had come down to 16 per cent (see Table 2.1). However, recent estimates by private sector firms suggest that captive power in Indonesia could even be as high as 16 GW (PWC 2016, p. 23).

Another indication of poor power quality is the system average interruption index (SAIDI) and the system average frequency index (SAIFI). These have fluctuated in the past decade, with a significant improvement in 2010–2015 (see Table 2.1). However, both indices are still considered to be far above the international standard. For reasonable electricity supply, the SAIFI (the number of customers facing blackouts as a proportion of total customers) should be between 0.9–0.92 per cent and the SAIDI should be between 53.4–69.6 minutes per year (Vitahayasrichareon, McGill & Nakawiro 2010). Reserve margins have been low, compared to recommended IEA levels of 20–30 per cent (IEA 2015, p. 106). Consequently, there were regular reports of blackouts, brown-outs and enforced supply cuts, especially in the regions and islands outside the Java–Bali grid (IEA 2015).

Table 2.1: Indicators of electricity shortages

	2002	2007	2010	2015
Captive power (kVA)	5,672,340	7,512,994	6,270,892	7,983,373
Total installed capacity (MW)	21,112	25,223	26,895	40,265
Captive power as % of total capacity	21.5	23.8	18.7	15.9
SAIFI (times/customer)	14.2	12.8	6.8	5.97
SAIDI (hours/customer)	14.4	28.9	7.0	5.31
Reserve margin %	18.7	15.5	7.3	17.0

Note: Reserve margin = (Installed capacity – peak demand)/Installed capacity.
Source: PLN Annual Statistics (various issues).

Compared to other countries at a similar economic level in the region, Indonesia still has low levels of electricity consumption and rural electrification (see Table 2.2).[2] Access to electricity was 86 per cent in 2015, below the rates in other lower middle-income

[2] By similar, I mean economies classified by the World Bank in the lower middle–income (US$1,026–4,035 per capita) and upper middle–income (US$4,036–12,475 per capita) group in the Asia-Pacific region (see the World Bank database at http://data.worldbank.org/about/country-classifications/country-and-lending-groups#Low_income).

countries in Asia. Installed capacity and energy consumption per capita are also below similar economies in the region, and even below that of countries at much lower per capita incomes, such as Vietnam.

Table 2.2: Regional comparison of basic electricity indicators in 2015

	GDP per capita (US$)	Electricity power consumption (kWh per capita)	Installed capacity (kWh per capita)	Electrification ratio (%)
Indonesia	2,952	590	142	86.2
China	4,433	2,631	738	99.4
Malaysia	8,373	3,613	894	99.4
Philippines	2,140	593	175	89.7
Thailand	4,614	2,045	698	99.3
Vietnam	1,224	918	175	97.6
East Asia (average)	4,713	2,094	na	90.7

Source: World Bank WDI database and PLN Statistics.

The investment survey of the World Economic Forum's Global Competitiveness Report shows that Indonesia scores poorly in relation to quality of infrastructure in general, and quality of electricity supply in particular (see Table 2.3). Indonesia ranks below China, Thailand and Malaysia. It is noticeable that between 2011 and 2015 Indonesia improved its rankings and scores in overall infrastructure quality, with small improvement in its electricity supply rankings.

Table 2.3: Quality of infrastructure and electricity supply in 2011 and 2015

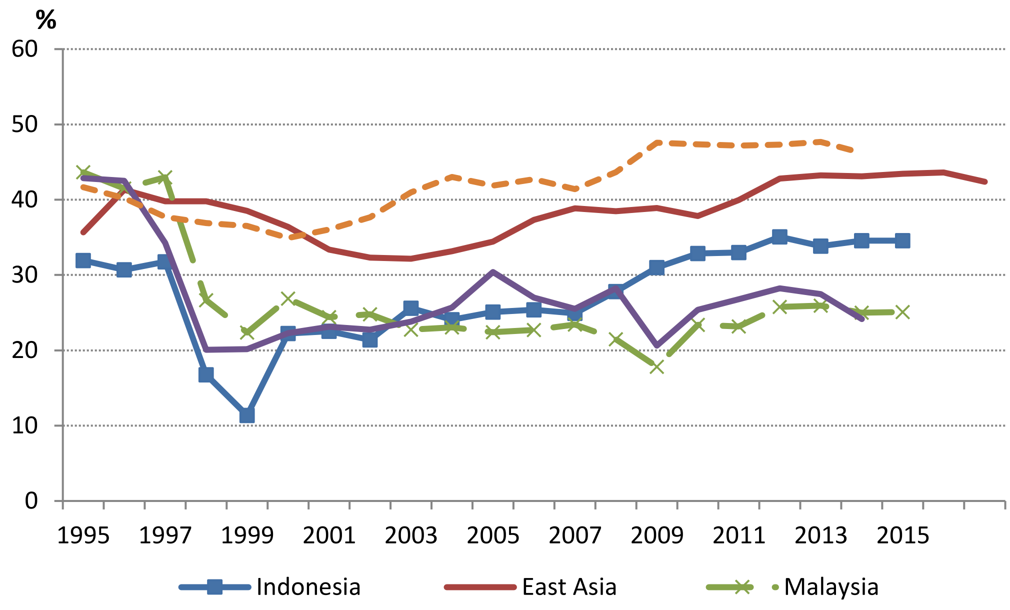
2011	Quality of infrastructure	Rank	Quality of electricity supply	Rank
Indonesia	3.7	92	3.9	93
China	4.3	69	5.2	59
Thailand	4.9	49	5.5	44
Malaysia	5.4	29	5.9	35
Philippines	3.6	98	3.7	98
Singapore	6.5	2	6.7	6
Vietnam	3.2	119	3.1	112

2015	Quality of infrastructure	Rank	Quality of electricity supply	Rank
Indonesia	4.2	60	4.2	89
China	4.7	42	5.3	56
Thailand	4.4	49	5.1	61
Malaysia	5.4	24	5.8	39
Philippines	3.4	95	4.0	94
Singapore	6.5	2	6.8	2
Vietnam	3.9	79	4.4	85

Source: The Global Competitiveness Report Investment Survey 2012–2013 and 2014–2015.
Note: The survey is conducted annually by the World Economic Forum and calculates a Global Competitiveness Index based on the responses of business executives in 144 countries (2011 sample) and 14,723 respondents in 141 countries (2015 sample). Respondents are asked to evaluate particular aspects of their operating environment. At one end of the scale, 1 represents the worst possible situation; at the other end of the scale, 7 represent the best possible situation. The survey consists of 14 modules including the quality of infrastructure and one indicator assessing the quality of electricity supply (World Economic Forum 2012, p. 69; 2015, p. 77).

To some extent, the lower quality of the power infrastructure reflects broader general investment patterns in the region. The investment to GDP ratio was consistently below the East Asian average from 1995–2010 (see Figure 2.2). Moreover, compared to neighbouring countries Thailand and Malaysia, only since 2008 has Indonesia succeeded in achieving higher domestic investment rates and managed to recapture levels similar to the ones before the Asian Financial Crisis of 1997–1998.

Figure 2.2: Investment to GDP ratio in select East Asian countries (1995–2015)



Source: World Bank Open Data (https://data.worldbank.org/).

2.3 Trends in total and renewable electricity generation

2.3.1 Renewable resource potential and total PLN generation trends

Indonesia has rich potential for RE, but realised generation is low (see Table 2.4). The exception is small hydropower projects, which have been the emphasis of donor-funded programs, where around one third of potential has been realised by 2009 (MEMR 2011).

Table 2.4: Potential and realised renewable energy capacity (2016)

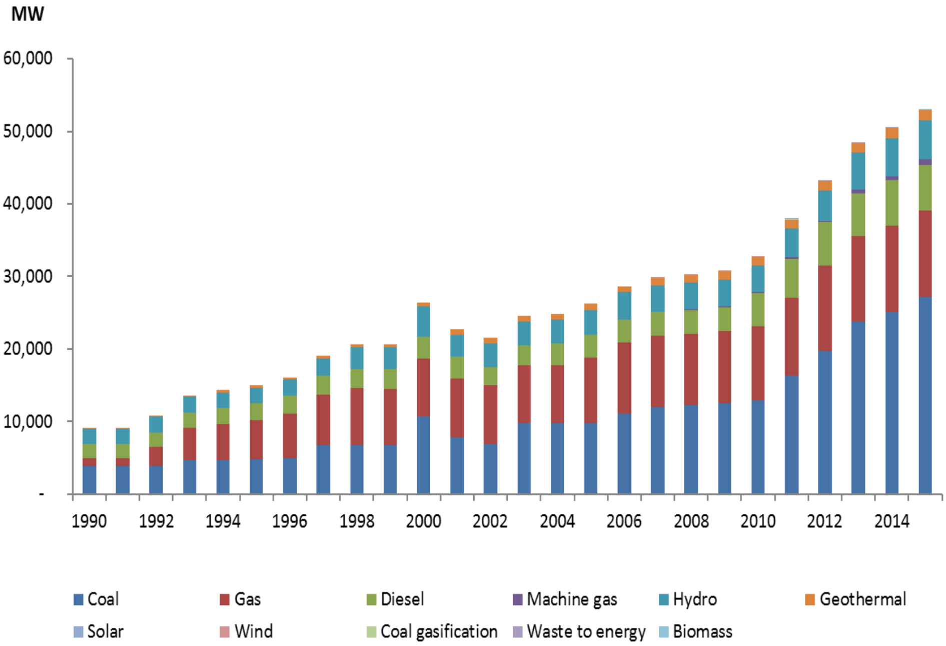
Renewable energy source	Resources	Installed capacity	Per cent
Hydropower	75,670 MW	3,566 MW*	4.7
Geothermal power	29,164 MW	1,224 MW*	4.2
Small hydropower	769.69 MW	182 MW*	28.31
Biomass	49,810 MW	na	na
Solar power	4.80 kWh/m2/day	13.5 MW**	-
Wind power	3–6 m/s	1.87 MW**	-
Uranium	3,000 MW***	30 MW**	1.0
Marine energy	49 GWe		

Notes: * Indonesia Energy Outlook 2013, as shown in PLN (2016b, p. 77); ** 2009 estimates in Sofyan (2011a); *** Only in Kalimantan Barat (Sofyan 2011a).

Source: Sofyan 2011a

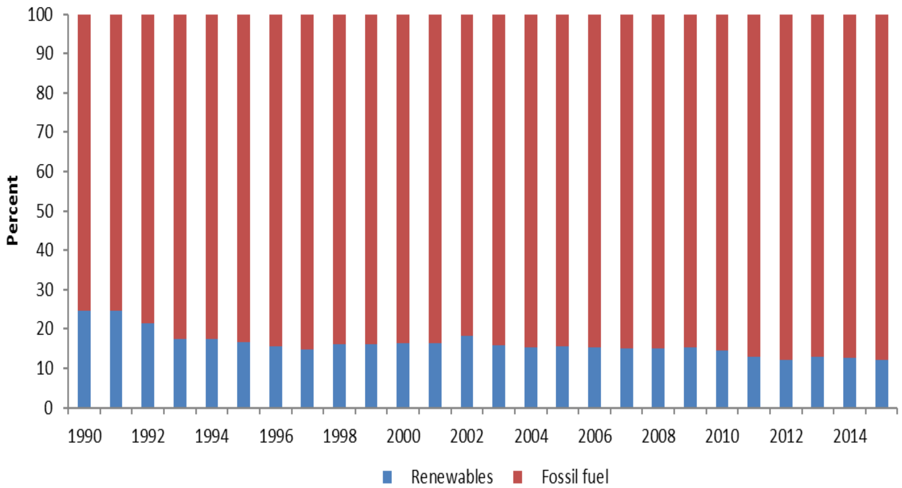
Despite the rich potential, the share of renewables in Indonesia's power supply fell over time (see Figures 2.3 and 2.4).

Figure 2.3: Total installed generation capacity (1990–2015)



Source: PLN Annual Statistics (various issues) (see Appendix 2.1).

Figure 2.4: Installed renewable and fossil fuel–based generation capacity (% of total)

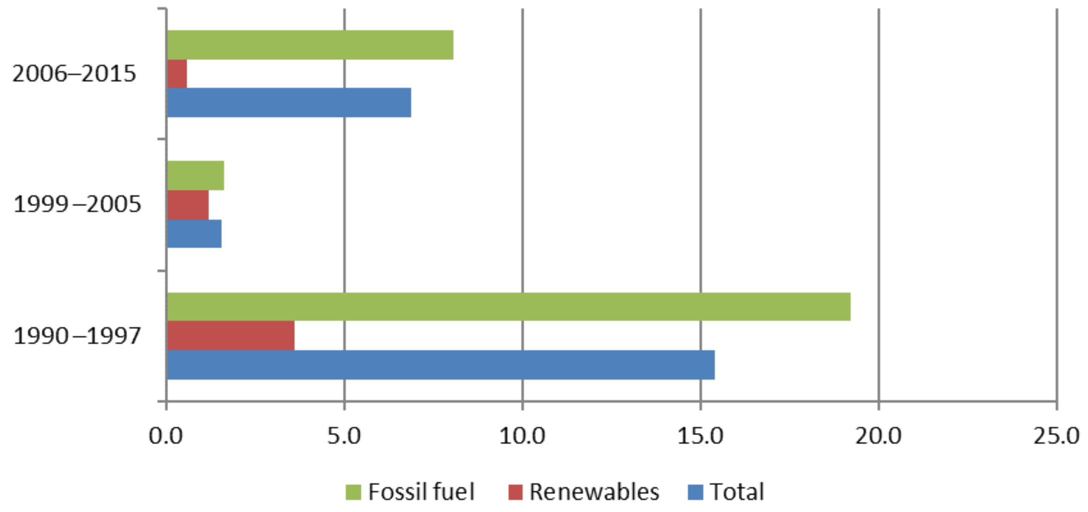


Source: PLN Annual Statistics (various issues) (see Appendix 2.1).

PLN's generation capacity increased from around 9,200 MW in 1990 to 40,000 MW in 2015. This means that total capacity grew on average by 13 per cent per annum during that period, or around 1,500 MW per year (see Figure 2.5 and Appendix 2.1).

Growth in electricity generation was relatively uneven and correlated with overall economic growth. Between 1990 and 2015, PLN's conventional, fossil fuel–based generation grew by 16 per cent, while renewable electricity grew by only 3 per cent per annum (see Figure 2.5). In the past two decades, growth in generation was particularly driven by gas (37 per cent) and coal (16 per cent). Within gas-fuelled generation, combined cycle grew strongly, showing 21 per cent growth on average. Within the renewable sector, geothermal grew strongest with 11 per cent (calculated from figures in Appendix 2.1).

Figure 2.5: Growth of PLN's supply mix (% YoY average)



Source: PLN Statistics (various issues) and author's calculations based on Appendix 2.1.

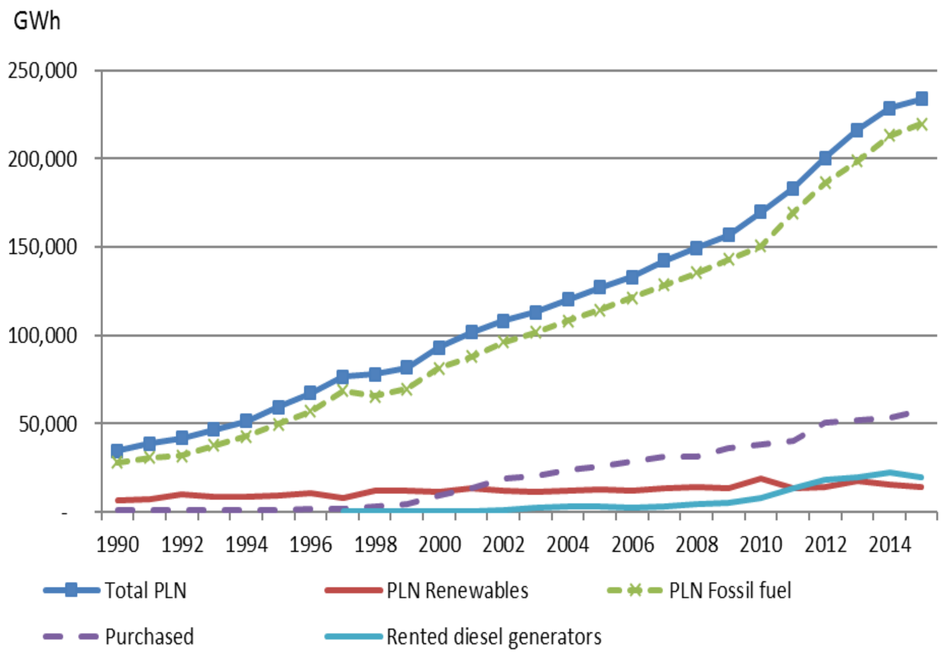
In 1990–1997, strong economic growth supported investment in the energy sector. In the 'post-crisis' period in 1999–2005, total electricity growth was sluggish at an average 1.6 per cent and renewable electricity at 1.2 per cent per annum. Growth in generation capacity has picked up since 2006, a period in which the government tried to attract investment into the electricity sector by launching the Fast Track Programmes 1 and 2 (FTP 1 and FTP 2 respectively). Total growth of electricity generation in this period was 6.9 per cent, with fossil fuel–based generation boasting 8.1 per cent, but RE was still trailing behind at 0.6 per cent.

2.3.2 Non-PLN and IPP generation

Outside of PLN, non-government entities also run both the construction of plants and generation of power. PLN buys the produced electricity in negotiated PPAs. These non-government entities are mostly private IPPs or community-based civil society organisations (CSOs). IPPs undertake commercial investments to generate electricity. CSOs are engaged in small-scale rural electrification projects to increase access to energy for the rural population. In recent years, the government has also promoted PPPs to set up energy projects.

Non-PLN generation, much of it from IPPs, has become increasingly important over time (see Figure 2.6). In the past two decades, total energy production increased almost sevenfold, from 34,800 GWh in 1990 to around 234,000 GWh in 2015. The share of electricity purchased by PLN from IPPs and other suppliers has increased from a mere 2.5 per cent in 1990 to 26 per cent in 2015. Renewable electricity production as a share of PLN-owned generation fell from 19.9 per cent in 1990 to 8.2 per cent in 2015, implying that PLN bought more non-renewable power from private IPPs. As a share of total electricity output (including purchased power), the share of renewables reached only 6.2 per cent in 2015.

Figure 2.6: PLN electricity production (1990–2015)



Source: Annual PLN Statistics (various issues).

PLN statistics show that between 1990 and 2011, a total of 30 IPP projects, amounting to 5,329 MW of capacity, were implemented. Fossil fuel–based generation constituted 4,348 MW (or 82 per cent), while only 981 MW (18 per cent) was renewables (PLN 2012).

Table 2.5: Realised IPP projects (MW) (1990–2011)

Fuel type	1990–1998	1999–2004	2005–2011	Total
Coal	0	2,450	872	3,322
Gas	300	405	261	966
MFO diesel	60	0	0	60
Fossil fuel based	**360**	**2,855**	**1,133**	**4,348**
Geothermal	165	350	271	786
Hydropower	0	0	195	195
Renewable energy	**165**	**350**	**466**	**981**
Total (fossil fuels + renewable energy)	**525**	**3,205**	**1,599**	**5,329**

Source: PLN (2012).

The history of IPP-based power generation can be divided into three phases. Prior to the Asian Financial Crisis in 1998–1999, the first wave of IPP projects started when the government enacted Law No. 15/1985 and special regulations in 1992 to attract private foreign investment into the electricity sector. The government provided guarantees that promised to cover PLN obligations under any PPA signed with IPPs. Foreign investors entered the electricity generation market in significant numbers, attracted by high forecast returns of projects.[3] Typically, the first large investors were closely connected to conglomerates run by President Suharto's family and PPAs were signed directly with them and their business allies (Wells & Ahmed 2007; Purra 2009).

Despite high expectations, a total of only 525 MW was installed during this period. Coal and diesel-based power plants made up 360 MW worth of installed capacity and 165 MW of renewable geothermal power capacity was installed by Chevron in Salak, West Java.

The government targeted much higher and quicker implementation of IPP projects before the crisis. Between 1990 and 1997, PLN signed 26 agreements with IPPs to generate both fossil fuel–based and renewable electricity. They represented close to 11,000 MW of capacity and an investment of US$13 billion at the time (Wells & Ahmed 2007). Geothermal projects represented 1,735 MW or 16 per cent of the total planned

[3] Internal rates of returns (IRRs) of 20–25 per cent were commonly cited among investors (PWC 2011).

generation capacity, while one hydropower project of 180 MW or 1.6 per cent of the total was also planned (Wells & Ahmed 2007). However, those generation targets were not achieved, as the economic and financial crisis of 1997–1998 put a halt to these projects. The rapid depreciation of the Rupiah rendered the terms of all contracts highly unfavourable for the government and PLN, who bore most of the currency and demand shortfall risks (Wells & Ahmed 2007). All 26 projects were postponed, resulting in disputes between the government and foreign investors between 1998 and 2004.[4]

In the second phase, the 'recovery period' (1999–2005), electricity policies were characterised by the uncertainties associated with the government's negotiations to settle debts with several IPPs and its failed effort to install the new market-oriented Electricity Law 20/2002, which was annulled by the Constitutional Court in 2004. In this period, growth of IPP-based capacity grew strongest, with around 3,205 MW connected to the grid, of which 350 MW constituted RE. This growth is mainly due to the implementation of projects signed before the crisis. These were two large coal projects under Paiton and Indonesia Power in 2000 and two large geothermal projects under Chevron and Star Energi (see Appendix 2.3). Realised projects in this recovery period were mostly part of the original IPP programme designed before the crisis and were finalised after debt settlement negotiations. No new investment from IPPs were realised during this period.[5]

The third phase in 2006–2015 saw a period in which the government attempted to rekindle IPP projects as part of a bigger Fast Track program. This took place amid legal uncertainties associated with the reinstalment of the old Electricity Law 15/1985 and the process leading up to and enacting the new Electricity Law 30/2009. A detailed breakdown of realised PLN and IPP projects is only available until 2011, with the implementation record of the Fast Track Programmes not fully published to date (see Section 2.4). By 2011, only around 1,600 MW worth of IPP projects had been realised, of which 466 MW was RE capacity.

[4] According to Wells and Ahmed (2007), out of the total 26 projects under the original IPP program, 14 were renegotiated, seven terminated, two taken over by PLN, one taken over by Pertamina, and two acquired by the government from the Overseas Private Investment Corporation.
[5] Appendix 2.2 includes 11 projects which belonged to the group of first large IPP projects contracted by PLN in the second half of the 1990s and which were eventually implemented after several delays.

2.4 Total and renewable PLN generation expansion programs

2.4.1 Fast Track Programme 1

The first stage of the crash programme, FTP 1, was announced in 2006. It aimed to complete the construction of 9,989 MW by 2009.[6] The program consisted almost entirely of the construction of coal-fired power plants by PLN at a cost of US$10 billion.[7]

The program suffered from long delays. The bulk of the engineering, procurement and construction (EPC) contracts were only signed in 2008, two years after the launch of the Fast Track Programme (PLN 2010a, p. 124). The government then had to extend FTP 1 until December 2014.[8] According to PLN, projects in Java experience on average of eight months delay, while projects in outer islands face even longer delays. Financing problems and delays in construction due to procurement problems were the main reasons cited among investors (PLN 2010b, p. 50). Higher than anticipated international coal prices also contributed to delays, as domestic producers demand PLN pay higher than domestically set prices.[9]

As of July 2015, 7,645 MW of coal-fired plant capacity have gone online (78 per cent of the total planned 10,000 MW), and the remaining plants are either in the process of being commissioned, constructed or were cancelled (Table 2.6) (PLN 2016a, p. 12).

[6] Presidential Regulation No. 71/2006. The initial official target was 9,975 MW. However, PLN figures show a target of 9,989 MW, which is used here.
[7] 'PLN announces plan to boost access to power by 20 percent', *Jakarta Globe*, 3 August 2011.
[8] Presidential Regulation No. 59/2009.
[9] See for example, 'Government promises coal for PLN despite price hikes', *Jakarta Post*, 24 January 2011.

Table 2.6: Fast Track 1 and 2 Programs

Program (medium to large projects)	Capacity (MW)	Status (MW) in 2015		
		Realised	Cancelled	Construction or commissioned
Fast Track 1	9,709			
PLN (coal)		7,645	62	2,126
Fast Track 2	17,458	na	na	na
PLN	5,799			
Geothermal	340			
Hydro	1,379			
Coal	3,800			
Gas-Combined Cycle	280			
IPPs	11,659			
Geothermal	4,515			
Hydro	424			
Coal	6,720			
Gas-Combined Cycle	-			

Source: PLN (2016b, p. 130).

2.4.2 Fast Track Programme 2

The second crash program, FTP 2, was launched in January 2010 and was originally scheduled to complete 17,458 MW of electricity generation capacity by 2014.[10] The program differed from the first, as it not only included coal-fired generation projects but also geothermal power plants.

Under this program, PLN was to implement 5,799 MW and IPPs 11,659 MW. Total fossil fuel–fired generation would constitute 10,800 MW (62 per cent) and renewables 6,658 MW (38 per cent) (PLN 2016b).

The final real status of the FTP 2 has never been officially confirmed,[11] but looking at the official PLN generation capacity statistics suggests two trends. First, coal-based power has increased significantly from 12,982 MW to 25,1094 MW from 2010 to 2014 (see

[10] The legal instruments are Presidential Regulation No. 4/2010 and Ministerial decree No. 15/2010.
[11] See for example, 'Indonesia's 2nd stage electricity fast-track program far below target', *Jakarta Post*, 15 October 2014, http://www.rambuenergy.com/2014/10/indonesias-2nd-stage-electricity-fast-track-program-far-below-target/.

Appendix 2.1). Although the PLN statistics show no breakdown of projects that belong to FTP2 and those that do not, this increase in coal-based generation capacity suggests that much of the planned capacity under FTP2 must have been completed. Second, only 215 MW of geothermal power generation capacity has been added between 2010 and 2015, clearly showing that the geothermal targets were not achieved. In 2011, a study commissioned by the government found that past resource surveys yielded inconsistent and upwardly biased results regarding the available potential of geothermal fields in Indonesia (Castlerock 2010). An updated survey estimates the real potential to be around 42 per cent lower than previously thought (ADB & World Bank 2015; Castlerock 2011).

2.4.3 The 35 GW program (2015–2019)

A five-year 35 GW program was announced by President Widodo in late 2014. The goal was to complete 35 GW of power generation projects by the end of his first term. The new five-year 35 GW superseded the FTP 2 and all projects planned for completion between 2015 and 2019 have been rolled into the 35 GW program. No specific regulation lists the 35 GW program projects. Rather, they consist of a combination of the previous FTP 2 and PLN's regular program.

These projects may be awarded through an open tender, direct appointment or direct selection. The current implementation status of the program is unclear. The vast share is allocated to coal-fired generation, with geothermal power targets significantly downgraded from previous objectives (see Table 2.7).

Table 2.7: The 35 GW program (MW)

Developer	IPP	PLN	Total	Share (%)
Coal	17,598	2,215	19,813	55.7
Hydro and SMPP	582	1,389	1,971	5.5
Natural gas	6,123	6,785	12,908	36.2
Geothermal	555	170	725	2.0
Wind	180	-	180	0.5
Biomass	30	-	30	0.1
Total	25,068	10,559	35,627	100

Source: PLN (2016).

2.5 Small and medium-scale renewable energy projects 1990–2015

SMPPs have been mostly initiated and run by government agencies outside PLN. Small-scale projects, mostly below 1 MW, or medium-size projects, between 1 and 10 MW, have been managed by several government agencies such as the MEMR and the Ministry of Home Affairs (MoHA). Frequently, these projects are donor-funded and implemented by non-profit-oriented CSOs or cooperatives (see Table 2.8). In these cases, it is difficult to assess the implementation record, as capacities generated are small and not all projects under these programmes are registered and connected to PLN.[12]

Table 2.8: Renewable energy projects outside PLN 1990–2015

Programs	Lead institutions	Financing source	Generation capacity	Implementation period
Mini Hydro Power Program (MHPP)	MEMR–DGEEU DG NREEC in 2011	GTZ	150 units with maximum of 150 kW	1991–2005
			480 kW – 7.7 MW	2006–2009
Green PNPM and MHPP	Ministry of Home Affairs (MoHA)	World Bank, GTZ	1.2 MW	2008–2013
ADB Renewable Energy Development Loan (MHP element)	MEMR–DGEEU PLN	ADB	60 MW	2002–2008, extended to 2013
IBEKA MHP projects	Private community based	Private and donor	53 projects, 3.8 MW	1991–2010
Solar Power	MEMR–DGEEU	BANPRES	3545 SHS units	1998–2002
	BPPPT	World Bank	1349 SHS units	1997–2002

[12] Larger projects are registered with PLN in its RUPTL planning documents. Programme evaluations showing statistics on implemented capacities, number of units and electricity purchased by PLN from small projects could not be obtained during the course of the fieldwork. Thus, there is a knowledge gap on the linkages between PLN and programs run by other agencies (i.e., the number of projects and electricity purchased by PLN from those projects).

Programs	Lead institutions	Financing source	Generation capacity	Implementation period
Desa Mandiri Energi Program (DME)	CMEA	German Ministry for Environment	3000 village energy projects	2007–2014

Notes: ADB = Asian Development Bank. BANPRES = Presidential Assistance/Support. BPPPT = Agnecy for the Assessment and Application of Tecchnology. CMEA = Coordinating Ministry for the Indonesian Economy. DG NREEC = Direcorate General for Renewable Energy and Energy Conservation. GTZ = German Agency for Technical Cooperation. DME = Village Energy Self Sufficient Program. IBEKA = Institue for People's Buiness and Economy. MEMR–DGEEU = Ministry of Energy and Mineral Resources–Direcotrate General for Electricity and Energy Utilization. PLN = National Electricity Company.
Source: GTZ (2009a, 2009b), GIZ (2011), World Bank (2001, 2010), ADB project data sheet (http://www.adb.org/projects/34100-013/main).

2.5.1 Small and medium-sized hydro projects

Concerted efforts to promote community-oriented small-scale renewable projects emerged only in the early 1990s. Aided primarily by the German aid agency GTZ (now GIZ), government and non-government entities installed around 150 micro hydro power (MHP) installations with capacities up to a maximum of 150 kW in West Java, Sulawesi and Sumatra between 1991 and 2005 (Tumiwa 2010; United Nations Development Programme (UNDP) 2007).

In 1999, the Mini Hydro Power Programme (MHPP) was launched, jointly implemented by GIZ and the Directorate General for Electricity and Energy Utilization (DGEEU) under the MEMR. The program emphasised capacity building for micro hydro equipment manufacture, policy support and productive end-use development (UNDP 2007). Between 2006 and 2009, MHPP supported the implementation of 96 MHP sites in Sulawesi and Sumatra with capacities ranging between 5 and 80 kW (GIZ 2011, p. 7). [13] However, with the establishment of the new Directorate General for New and Renewable Energy and Energy Conservation (NREEC) in 2010, the organisational counterpart changed and required a revision of the project planning by 2011.

In 2008, the government integrated elements of MHPP into larger community development projects. Under the leadership of the MoHA, the government started to run a five-year (2008–2013) US$54.8 million environmental pilot project, the Green

[13] According to IEA (2009), the MHPP has supplied 20,000 rural households with electricity. PLN started to buy electricity from private generators starting in 1999 at relatively higher prices and reportedly have sold it at subsidized prices to demonstrate the technical feasibility of micro hydro projects (UNDP 2007).

PNPM (*Program Nasional Pemberdayaan Masyarakat Mandiri Perdesaan*) (World Bank 2010). A key feature of the program is that it integrates the technical expertise of the GTZ MHPP in to the participatory PNPM model. The PNPM community empowerment program has been in place since the end of the 1990s and several micro hydro schemes were run under the program. However, the record was mixed, with many MHP sites reporting a lack of operational support and maintenance (GIZ 2011, p. 8). It was hoped that marrying a MHP 'Technical Support Unit' with the institutional framework of the PNPM scheme would improve the sustainability of those village programs that run MHP plants.

In essence, the Green PNPM provides block grants directly to communities to fund 155 MHP sites, but implementation is lagging behind. These MHP sites are in Aceh, Bengkulu, North Sumatra, West Sumatra, North Sulawesi and West Sulawesi Provinces. Once they are fully operational, these MHP schemes are projected to collectively generate over 1,200 kW of electricity and provide RE services to over 20,000 connected households (World Bank 2010). However, by 2012, only 40 of these schemes had been commissioned and handed over to communities, making it a tall order to achieve the stated objectives (Castlerock 2012, p. iv). But assessments of 15 MHP projects that were up and running were positive in terms of economic, social and environmental returns of the projects (Castlerock 2012, p. 29).

The combined Green PNPM/MHPP scheme is the biggest MHP programme in the country and is seen as pilot project for large-scale dissemination of renewable energies to rural Indonesia by innovative fiscal means. Specifically, it served as a model for the Special Allocation Fund for small-scale RE under the MEMR.[14] This new mechanism, established in 2016, will provide US$100 million annually to electrify remote rural areas in underdeveloped areas with RE. Local governments can use these funds to construct, rehabilitate or extend grids of new micro hydro plants and install solar systems. It is unclear, however, how that funding mechanism can or will be linked to the existing MHPP schemes. This suggests further coordination problems to be sorted out with other government agencies like the MoHA running the Green PNPM/MHPP schemes.

[14] MEMR Regulation No.3/2016

In 2002, the ADB approved a loan to PLN for RE development projects, which contained a significant proportion of mini hydro projects to be operated by IPPs. The loan came into effect in 2004 after delays in signing and aimed to be completed in 2008. The objective of the projects was to deliver about 82 MW of new generation capacity from RE-based sources and expand the distribution systems and connections by around 76,000 new customers. Specifically, 10 hydropower projects and two geothermal projects were to be constructed in Eastern Indonesia (see Appendix 2.4). However, implementation suffered from significant delays due to procurement problems and the project has been extended from the original closing date of September 2008 to September 2013 (see Appendix 2.4).[15]

The most successful non-government organisation in developing micro hydro schemes is the *Institut Bisnis dan Ekonomi Kerakyatan* (IBEKA) foundation. This organisation specialises in delivering renewable technology to rural communities. During 1991–2010, it succeeded in implementing 53 projects that generated close to 4 MW of electricity. It puts the training and capacity building of local communities to run and maintain the hydropower plants at the core of its agenda.[16]

2.5.2 Solar power programs

The government has undertaken two major solar programs in the past. First, under the Solar Power for Rural Electrification Scheme (*Listrik Tenaga Surya Masuk Desa*) and funded by the Presidential Aid Program (BANPRES), 3,545 solar home systems (SHSs) units were installed in 13 provinces between 1988 to 1992 (World Bank 1996). By the mid-1990s around 20,000 SHS units were reportedly installed as a result of various government-funded projects (World Bank 1996).

Second, the largest programme to promote the use of solar energy occurred in 1997, when the World Bank and GEF-financed program to install 200,000 SHS was launched. However, the project was affected by the Asian Financial Crisis and, by end of 2000, only a total of 1,349 SHS units were installed (World Bank 2001, p. 4).

---

[15] ADB project data sheet (http://www.adb.org/projects/34100-013/main). Specifically, three mini hydro power projects in Flores, Lombok and Papua and the geothermal project in Ulumbu, Flores face difficulties with contractors and social issues. Termination is being considered.

[16] Interview with Tri Mumpuni, Head of IBEKA. The list of implemented projects can be downloaded from http://ibeka.netsains.net/.

Since 2005, solar systems have been installed under the MEMR-run Village Energy Self Sufficient Programme DME (Desa Mandiri Energi), which aims at the electrification of rural villages through off-grid RE systems. Under this program, one of the targets was to install approximately 100,000 SHSs, but the implementation record is unclear (IEA 2008).

In 2009, the Indonesian MEMR announced that Indonesia had allocated US$62.4 million for 2010 to construct solar PV installations with a total capacity of 2,200 kWp for 150,000–200,000 rural households and that it aimed to construct 250 solar-powered plants under the Ministry's 2010–2014 power generation blueprint (OECD & IEA 2009, p. 45).[17]

In 2010, PLN launched PV power pilot projects in six locations.[18] In 2011–2014, PLN planned to develop 103,773 kWp of small PV systems in 674 locations and 302 MW of big scale PV (>5 MW) in 71 locations (Sofyan 2011b). These pilot projects, under the so-called '1000 islands Programme', will be extended with a target of developing 170 MW at over 900 locations. In 2015–2020, a comprehensive PV system for rural electricity will be developed and total solar capacity should reach 620 MW. After 2020, it is hoped that the PV market has matured to develop solar power at full-fledged commercial scale. The initial phase with pilot projects is supported by donor aid money from the ADB and the GIZ.[19]

In 2011, PLN launched the Super Extra Hemat Energi (Super Extra Energy Savings) Program in Eastern Indonesia, which provided communal PV systems to rural households. Sambodo (2015) argues that the program was successful by increasing access to electricity for households in a relatively short time from around 4,000 customers in March 2012 to 113,715 customers in February 2013. However, the utility had difficulties in collecting regular, monthly payments from customers and lacks the technical capacity at the local levels for monitoring and evaluating the program and providing maintenance services (Sambodo 2015, p. 118).

[17] Interview with MEMR staff, Renewable Energy Section.
[18] Bunaken, Derawan, Trawangan, Naira, Raja Ampat and Tomia. Presentation material and Interview with Mohamad Sofyan, PLN, Head of Division of Renewable Energy.
[19] Interviews with Thorsten Schneider, KfW and Bagus Mudiantoro, ADB Indonesia Office.

2.5.3 Wind power

Wind power has been implemented only on an experimental basis from 1990–2015, with wind turbine prices still expensive in Indonesia. Several wind power projects have been set up by PLN on a trial and experimental basis. Around 14,725 kW in generation capacity are projected to be implemented from 2010–2014 (Sofyan 2011a). The biggest PLN-run wind power turbine has been installed at Selayar island with a generation capacity of 100 kW (Indonesia Wind Energy Society 2012).

2.5.4 Biomass

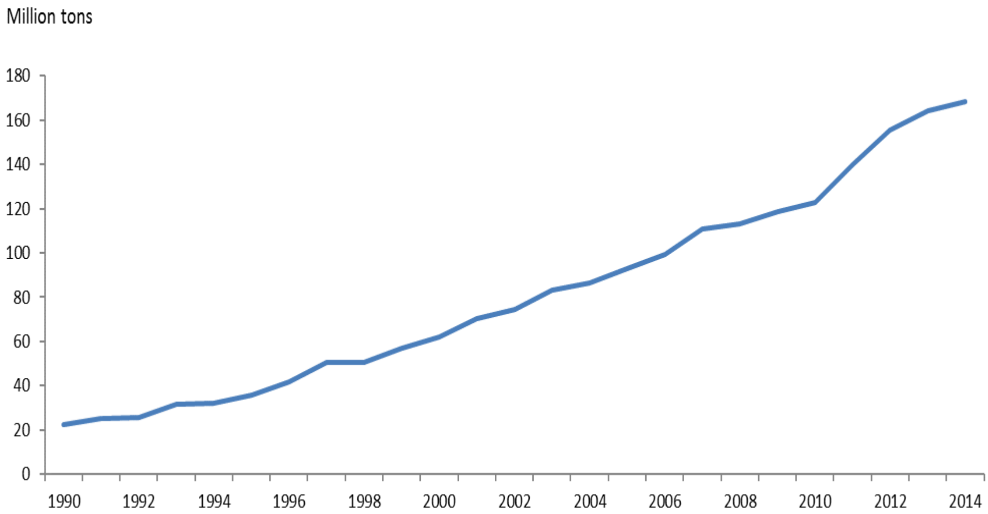
Between 2001 and 2011, PLN purchased 61 MW worth of generation capacity based on biomass, biogas and solid waste and connected 11 bioenergy power plants to the grid (Hutapea 2012) (see Appendix 2.3). PLN also signed several agreements with biomass developers to purchase 802 MW worth of power in 2011–2014. They consist of 15 IPPs and six private plants selling excess power (Sofyan 2011a; Hutapea 2012).

2.6 The outlook for renewable energy: Is Indonesia's energy sector locked into a carbon-intensive path?

To date, we have seen that RE growth has been slow, and the share of RE in the total electricity generation mix has been declining. To provide some comparative context, it is useful to analyse Indonesia's electricity mix within the framework of the 'electricity ladder' (Burke 2010). This theoretical framework suggests that as a country's income per capita rises, its electricity supply mix follows a predictable pattern. As countries become richer, the energy mix becomes more diversified, with coal, natural gas, nuclear power and renewables featuring more heavily, while hydropower and oil decrease in importance. However, the pace at which a country climbs up the electricity ladder is also dependent on its resource endowment—if a country is blessed with an abundance of a specific fossil fuel resource, it is less likely to climb up the 'electricity ladder' when compared to similar economies (Burke 2010, pp. 616–626).

In the case of Indonesia, the rise of coal and the decline of hydropower suggest that the country follows the predicted path. The increased share of gas and the stunted development of the RE sector points to the endowment effect as a plausible factor. The endowment effect also explains the strong role of coal in the generation mix, which makes Indonesia's energy path a carbon-intensive one. Indonesia's coal resources are estimated to be 123 billion tonnes (PLN 2016). Most is sub-bituminous (66 per cent), 14 per cent is bituminous, and lignite or 'brown coal', the most polluting type, accounts for 20 per cent. Indonesia's coal reserves—the amount of coal that is economically and technically mineable—are estimated to be about 28 billion tonnes (PLN 2016, pp. v–3). A large share of domestic coal consumption will go to meet PLN's power generation needs, with estimates that coal consumption by Indonesia's power sector will double from about 75 Mt to 150 Mt between 2015 and 2022 (IEA 2016). Carbon dioxide emissions from the electricity have increased steadily in the past 25 years (see Figure 2.7).

Figure 2.7: Carbon dioxide emissions from the electricity sector in Indonesia (1990–2014)

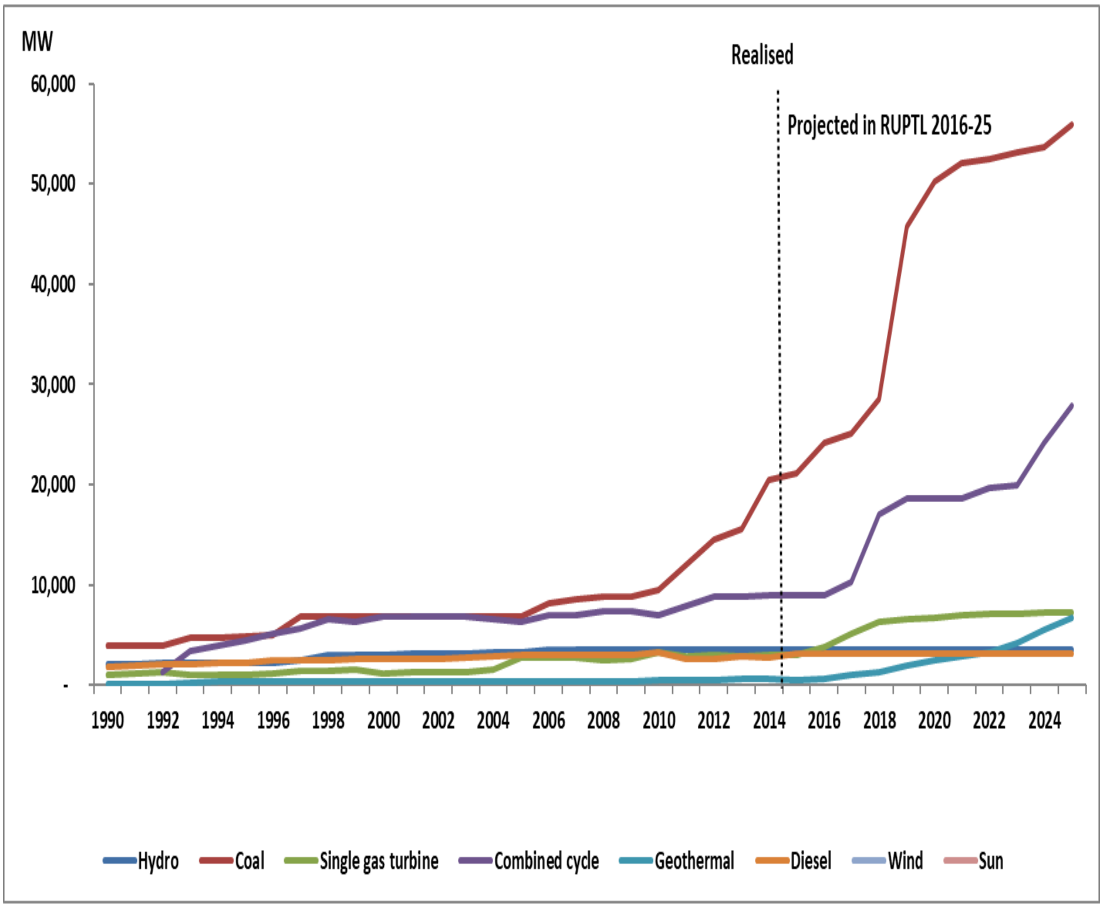


Source: OECD and IEA database (http://www.oecd-ilibrary.org/energy/data/iea-co2-emissions-from-fuel-combustion-statistics_co2-data-en).

The question now is whether the energy sector is in danger of being locked into a carbon-intensive path? This is an important question, because Indonesia has committed to reduce total greenhouse gas emissions by 29 per cent from business-as-usual levels by 2030 under the Paris Conference of the Parties 21 agreement and has subscribed to climate action policies under the Sustainable Development Goals (Badan Perencanaan dan Pembangunan Nasional (BAPPENAS) 2015).

Under its latest Annual Business Plan (RUPTL 2016-25), PLN plans to increase generation capacity from current levels of 44,000 MW to 116,000 MW in 2025 (see Figure 2.8). This means an annual increase of capacity of 8,400 MW. The targeted capacity for renewables is 21,138 MW, which is only 18 per cent of the total supply mix (PLN 2016). This includes the 35 GW expansion program with its large share of coal-fired generation (discussed in Section 2.4.3).

Figure 2.8: PLN 2016–2025



Source: PLN (2016b).

With coal plants playing a massive role in the government's current generation expansion plans, Indonesia is in danger of creating carbon liabilities for decades to come.[20]

[20] Recent comments by the Minister of Energy and Mineral Resources indicate that the expansion of coal-powered electricity generation has to be limited, at least for the densely populated island of Java ('No new coal power stations in Java, Indonesia energy minister says', *Reuters*, 12 October 2017, https://www.reuters.com/article/indonesia-power-coal/no-new-coal-power-stations-in-java-indonesia-energy-minister-says-idUSL4N1MN4ZI).

2.7 Conclusion

This chapter has shown that Indonesia's energy path is in danger of being over-reliant on coal in the coming decades, despite the existence of ample resources of renewables and programs to promote them. Analysis of the utility's electricity supply trends in the period 1990–2015 shows a significant increase of the role of coal and a decline of renewables in the generation mix. While the share of coal has increased from 43 to 49 per cent, the share of renewables declined from 25 to 12 per cent from 1990–2015. This decline of the share of renewables has been driven by a large decrease in the share of large-scale hydropower and stagnation of geothermal power generation. Small-scale RE supply has been promoted across various technologies, but the implementation of projects has been mixed. A closer look at the government's electricity expansion programs—specifically under the FTP 1 and 2 programs—shows that while coal- and gas-fired projects have been largely implemented, realisation of RE investment has been plagued by delays and uncertainties.

Indonesia's energy path and supply mix suggests that the prominent rise of coal and the stunted development of renewables is due to an 'endowment effect', as the availability of large coal reserves slows down incentives to diversify the energy sources. The next chapter explores the policy and regulatory problems in incentivising RE investment.

Appendix 2.1: Installed generation capacity (1990–2015) (MW)

	1990	1995	2000	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Coal	3,941	4,821	10,672	9,750	11,170	12,014	12,294	12,594	12,982	16,318	19,714	23,813	25,104	27,225
Gas	1,073	5,417	8,067	9,005	9,748	9,805	9,841	9,942	10,175	10,673	11,787	11,708	11,898	11,875
Gas Turbine	1,073	1,002	3,805	3,099	3,103	3,220	3,069	3,136	3,822	4,236	4,344	4,389	4,311	4,311
Combined cycle	-	4,414	6,863	6,920	7,660	7,700	8,010	8,010	7,590	8,481	9,461	9,852	10,146	10,146
Diesel	1,870	2,265	2,916	3,208	3,165	3,212	3,273	3,256	4,570	5,472	5,974	5,935	6,207	6,275
Machine Gas	-	-	-	3	21	33	67	71	93	170	199	448	611	819
Hydro	2,095	2,178	4,199	3,411	3,719	3,695	3,698	3,702	3,734	3,944	4,146	5,166	5,229	5,262
Geothermal	140	305	525	850	850	980	1,052	1,189	1,189	1,226	1,336	1,344	1,404	1,439
Solar	-	-	-	-	-	-	-	-	0	1	4	9	9	14
Wind	-	-	-	-	-	0	0	1	0	1	1	1	1	1
Coal gasification	-	-	-	-	-	-	-	-	-	41	41	6	6	6
Waste to energy	-	-	-	-	-	-	-	-	-	26	26	26	36	36
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	1
Total	9,118	14,986	28,980	27,241	29,688	30,854	31,463	31,959	33,980	39,916	45,246	50,988	53,064	55,532
Renewables	2,235	2,483	4,724	4,261	4,569	4,675	4,750	4,892	4,923	5,199	5,513	6,545	6,679	6,751
Fossil fuel	6,883	12,503	24,256	22,980	25,119	26,179	26,713	27,067	29,056	34,717	39,732	44,443	46,385	48,781

Source: PLN Annual Statistics (various issues).

Appendix 2.2: Realised IPP operations (1990–2011)

No.	IPP Developer/Location	Fuel Type	MW	CoD
Java–Bali				
1	Chevron Geothermal/Salak, West Java*	Geothermal	165	1997
2	PT Cikarang Listrikindo/Cikarang*	Combined cycle	300	1998
3	Chevron Geothermal/Darajat *	Geothermal	180	2000
4	Star Energi Magma Nusantara/Wayang Windu unit 1*	Geothermal	110	2000
5	PT Paiton Energi/Paiton1- PEC*	Coal Steam Fired	1,230	2000
6	PT Jawa Power/Paiton II – JP*	Coal Steam Fired	1,220	2000
7	PT Geodipa Energy/Dieng*	Geothermal	60	2002
8	PT Sumber Segara Cilacap*	Coal Steam Fired	562	2007
9	Chevron Geothermal Darajat unit 3*	Geothermal	90	2007
10	PT Pertamina Kamojang 4*	Geothermal	60	2008
11	Star Energi - Magma Nusantara W.Windu unit 2*	Geothermal	110	2009
12	PT Dalle Energy Batam	Gas	55	2005
13	PT Mitra Energi Batam	Gas	55	2005
14	PT Indo Matra Power/Batam	Gas	17	2005
15	Perum Jasa Tirta/Pruwakarta, West Java	Hydropower	150	2012
16	PT Jembo Energindo/Batam	Gas	24	2008
17	Aggreko International Project Ltd/Batam	Gas	30	2008
Sumatra				
18	PT Asrigita Prasarana/Palembang	Gas	150	
19	PT Dizamatra Sibayak*	Geothermal	11	2009
20	PT Baijrada Sentranusa/Asahan, North Sumatra	Hydropower	180	2010
21	PT Cipta Daya Nusantara/North Sulawesi	Hydropower	3	2007
22	PT Guo Hua Energi/South Sumatra	Coal	227	2011
23	PT Metaepsi Pejebe Power Generation/South Sumatera	Gas	80	2005
24	PT Makassar Power/Pare Pare	Diesel	60	1998
25	PT Pusaka Jaya Palu P. Tawaeli	Coal Steam fire	27	2007
26	PT Cahaya Fajar/Kaltim Embalut	Coal Steam fired	45	2008
27	PT Energi Sengkang/South Sulawesi	Gas	255	1999
28	PT Fajar Futura Energy/Luwu, South Sulawesi	Hydro power	2	2010
29	PT Sulawesi Mini Hydro Power	Hydro power	10	2011

30	PT Ekploitasi Energi Indonesia/Central Kalimantan	Coal	11	2011
Total MW (excluding Project no. 15)			5,329	
Renewable MW			981	
Fossil fuel–based MW			4,348	

Note: * Project was already part of the first list of IPP projects negotiated with PLN in 1995–1998.
Source: PLN (2011, 2012).

Appendix 2.3: Realised Bioenergy Projects (Power Purchased by PLN)

No.	Company	COD	Contract	Location	Type of Biomass	Capacity (MW)
1	PT Riau Prima Energy	2001	Excess power	Riau	Palm waste	5
2	PT Listrindo Kencana	2006	IPP	Bangka	Palm waste	5
3	PT Growth Sumatra	2006	Excess power	Sumatera Utara	Palm waste	6
4	PT Indah Kiat Pulp & Paper	2006	Excess power	Riau	Palm waste	2
5	PT Belitung energy	2010	IPP	Belitung	Palm waste	7
6	PT Growth Sumatra	2010	Excess power	Sumatera Utara	Palm waste	9
7	PT Pelita Agung	2010	Excess power	Riau	Palm waste	5
8	Permata Hijau sawit	2010	Excess power	Riau	Palm waste	2
9	PT Navigat Organic	2011	IPP	Bali	Municipal solid waste	2
10	PT Navigat Organic	2011	IPP	Bekasi	Municipal solid waste	8
11	PT Growth Asia	2011	Excess power	Sumatera Utara	Palm waste	10
Total on-grid capacity						61

Source: Database of Renewable Energy Division, MEMR, Presented by Hutapea (2012).

Appendix 2.4: ADB-funded IPP projects under the Renewable Energy Development Loan (2002–2013)

	Project	Location	Capacity	Implementation status
1	Api Roudlotuth Tholibin (Wangan Aji MHP)	Central Java	2x70 kW	2007
2	Merasap	West Kalimantan	2x0.75 MW	in operation
3	Lobong	North Sulawesi	2x0.8 MW	in operation
4	Poigar 2	North Sulawesi	2 x 16 MW	August 2013
5	Mongango	Gorontalo	1.2 MW	in operation
6	Prafi	Papua	1.6 MW	Aug-13
7	Tatui	Papua	1.2 MW	cancelled
8	Amai	Papua	1.1 MW	cancelled
9	Genyem	Papua	2 x 9.6 MW	August 2013
10	Santong	Lombok Nusa Tenggara Barat (NTB)	0.85 MW	unclear
11	Ndungga	Flores Nusa Tenggara Timur (NTT)	2 x 0.95 MW	unclear

Source: ADB project data sheet (http://www.adb.org/projects/34100-013/main).

Chapter 3: The Evolution and Effectiveness of the Indonesian Feed-in Tariff Regime: The Case of Small and Medium Power Producers

Abstract

This chapter provides an analysis of the evolution of the Indonesian FIT regime and assesses its effectiveness in providing incentives to SMPPs. It provides an historical analysis of the FIT regulations and a qualitative assessment of data from interviews conducted with stakeholders in the RE policy and investment community. The empirical analysis captures mostly the effectiveness of the regulations up to 2012 and has been complemented by a review of the literature covering regulations up to early 2017.

Overall, the chapter finds that FITs were mostly ineffective in that PLN did not automatically take up renewables, with many small and medium-scale developers reporting protracted PPA tariff negotiations with the utility that significantly slowed down implementation of projects. Factors that cause this state of affairs include PLN's preference for cheaper coal- and gas-fired power generation, lack of mandatory mechanisms for the utility to buy renewables, flaws in the design of the FITs preventing them from acting as premium prices to attract developers and wider investment climate issues in the power sector.

3.1 Introduction

As shown in Chapter 1, the share of RE in Indonesia's electricity mix has shrunk. Aside from wider macroeconomic factors and general investment climate issues, slow investment might also point to the lack of a policy and regulatory environment conducive to the RE sector. Indonesia has experimented with price-based regulations to promote RE supply since the mid-1990s. These regulations have undergone various changes in design over the past two decades to apply elements of FIT regimes. These FIT regulations were mainly applied to attract investment from SMPPs and geothermal IPPs.

This chapter provides an analysis of the evolution of the Indonesian FIT regime and assesses its effectiveness in providing incentives to SMPPs. It adds to the Indonesian energy literature by providing a historical analysis of the FIT regulations and a qualitative assessment of data from interviews conducted with stakeholders in the RE policy and investment community. Section 3.2 provides a review on the role of FITs as policy instruments. Section 3.3 charts the regulatory evolution of the Indonesian FIT regimes for SMPPs. Section 3.4 analyses the main policy themes emerging from analysis of secondary data and interviews with SMPP representatives and government stakeholders. Section 3.5 presents findings from discussions with stakeholders in the geothermal sector. Section 3.6 concludes the chapter.

3.2 Methodology

The main objective of this chapter is to provide a historical analysis of the FIT regime in Indonesia and obtain the perceptions of stakeholders in the RE sectors on the effectiveness of these regulations. Field research was conducted in 2011–2012 in Jakarta, using semi-structured interviews to obtain information from project developers and policymakers in the RE and electricity sectors. These included mainly managers of SMPPs, developers of geothermal projects and policymakers from relevant line ministries, donor agencies and state utility PLN (see Appendix 3.1).

The choice of semi-structured interviews was motivated by the desire to, firstly, engage stakeholders on a broader policy discussion on the effectiveness of FIT regulations within the context of the Indonesia's macroeconomic and investment conditions. A secondary objective was to obtain project-specific information and perceptions from stakeholders operating on the ground. In other words, the use of qualitative interviews would enable the researcher to learn about macro-level 'big picture' issues, while also probing stakeholders for more specific, data-oriented issues.

Several advantages are commonly associated with semi-structured interviews. One advantage is that they are less intrusive and allow for two-way communication. This way, the interviewer is able to confirm already known facts, but it also opens up avenues for learning. Further, the resource persons interviewed are frequently able to not only provide answers but reasons for the answers. Lastly, more sensitive topics can be easier touched on in an open-ended conversation, rather than using standardised, very detailed questionnaires (Food and Agricultural Organization 1990; Rea & Parker 2005).

The questionnaire consisted of an introduction of four main themes along which the interview proceeded: Information about the project, perceptions on the FIT regulations, perception on general policy environment for RE investment and the role of PLN in project development, and other investment constraints (see Appendix 3.1). Only a few lead questions in each theme were fixed, with more specific questions arising during the conversation to probe for more detailed explanations. The interviews were conducted following the guidelines issued by the Human Ethics Research Committee of the Australian National University. [21] Interviewees were informed about the purpose of the research and asked to sign a consent form at the end of the interview.

3.3 Feed-in tariffs as instruments to promote renewable energy

FITs are technology-based policy instruments with the aim of promoting the uptake of RE. FITs come in various forms and there is no common definition that would capture all types. A widespread definition of FITs sees them as 'laws and regulations that provide a premium rate over a fixed period of time for each unit of electricity fed into the grid' (Mendoncana, Jacobs & Sovacol 2009, p. xxi). The utility buys up renewable electricity from producers at these mandated prices. FITs aim to provide price stability and a secure return to investment to producers. The FIT can be varied to spur new emerging technologies or to achieve social ends (Mendoncana, Jacobs & Sovacol 2009, p. 16).

Generally, FITs have three elements: guaranteed grid access, long-term contract for the produced electricity, and prices based on the cost of generation plus a reasonable rate of return (REN21 2011, p. 56). Thus, a basic FIT pays a guaranteed price for power generation from a RE source, most commonly for each unit of electricity that is fed into the grid by a producer (REN21 2011, p. 56). FITs can be at a fixed price that is independent of electricity market prices or as premium payments at above-market prices (IPCC 2011, p. 899).

[21] See https://services.anu.edu.au/research-support/ethics-integrity/human-research-ethics-committees.

How effective have FITs been in promoting RE? The global picture on the effectiveness of FITs suggests differential effects across countries with different income levels. Baldwin et al. (2017) applied cross-country regression analysis to compare policy instruments and other factors that influence the adoption of RE. They found that FITs and RPSs were the main drivers of the generation of *non-hydroelectric* RE in high-income countries. FITs were the main driving force for both *total and non-hydroelectric* RE development in middle-income countries. In low-income countries, subsidies have a positive and statistically significant relationship with *non-hydro* RE development (Baldwin et al. 2017, p. 18). Indonesia is now a middle-income country, but Baldwin et al. (2017) classified Indonesia as a low-income country for the period of their investigation (1990–2010).

The literature on the experience of FIT policies in the developing world suggests that FITs were also effective in promoting small-scale RE power supply. In 2008, Kenya introduced FIT legislation and did so based on international best practice (Mendoncana, Jacobs & Sovacol 2009, p. 102). Its energy mix is dominated by large hydropower and fossil fuel energy, with an increasing share of geothermal power whose price is already competitive. However, with large hydropower capacity waning due to reduced precipitation, the government wanted to scale up production from other renewables to meet growth in demand. Thus, the FIT is aimed largely at biomass, small-scale hydropower and wind (Mendoncana, Jacobs & Sovacol 2009).

The basic design of the Kenyan FIT scheme contained the following elements. First, the costs of the FIT were passed on to all electricity consumers. Second, capacity caps on individual plants were used. Third, the duration of tariff payment is fixed for 15 years. The results of the FIT scheme were positive as the prices for all renewables stayed in the same price range as conventional power and were stable, while crude oil prices fluctuated significantly. Moreover, one year after the FIT was launched, all planned projects—equal to 500 MW—were installed, with additional capacity in wind power in the pipeline (Mendoncana, Jacobs & Sovacol 2009, pp. 103–104).

South Africa introduced a FIT scheme in 2009 in the wake of the government’s decision to abandon long-held plans to invest in the expansion of nuclear power capacity. The economic crisis of 2008 rendered the country’s nuclear ambitions infeasible due to the high costs of capital and policymakers decided to expand the role of renewables in future energy planning. After a process of public consultation, which resulted in significantly higher tariff rates than originally proposed by the government, the FIT scheme was legislated in March 2009 (Mendoncana, Jacobs & Sovacol 2009, p. 105).

The FIT scheme in South Africa targets generation by landfill gas, small hydro (less than 10 MW), wind power and concentrated solar power. Biomass power is supported by other support schemes and the law leaves the door open for other RE technologies to be included in future FIT schemes. Tariff payments are guaranteed for a period of 20 years, after which the IPPs are free to negotiate new PPAs with the grid operator. The FIT scheme also includes stipulations for tariffs to new plants to be indexed to inflation and an annual review of the tariffs in the first five years and every three years after that (Mendoncana, Jacobs & Sovacol 2009, 105).

In Asia, several developing economies have started FIT programs. China has introduced a FIT for wind power and utility-scale solar plants in 2009. India has introduced FITs for solar power in several states, notably West Bengal, Rajasthan, Gujarat and Punjab (Mendoncana, Jacobs & Sovacol 2009, pp. 107–108). Malaysia aims to meet a RE target of 3,000 MW by 2020 and introduced FITs aimed mainly at solar PV and bioenergy (REN21 2011, p. 55).

Thailand is regarded as a good example for the integration of a FIT scheme into an already well-designed, sequenced and effective RE policy (IPCC 2011, p. 902). The government started with a Small Power Producer (SPP) Program in 1992, which promoted standardised interconnections and PPAs for generators of up to 90 MW. This resulted in the proliferation of mostly bagasse co-generation projects. In 2002, a Very Small Power Producer Program was introduced which further streamlined utility interconnection criteria for generators up to 1 MW (IPCC 2011, p.902).

In 2006, the Thai government enacted a FIT scheme that pays out a premium on top of the avoided costs of the utility. It is also differentiated by technology and generator size and is paid out for a guaranteed 7–10 years. Complementary measures included subsidies for projects that offset diesel use in remote mini-grids and further incentives to accommodate SPP. Incremental costs are passed on to the consumers, with consumption subsidies for small consumers. Other supporting policies included an eight-year corporate tax holiday, reduction and exemption of import duties, low-interest loans and government equity financing. These policies resulted in a significant increase in biomass and solar power generation capacity (IPCC 2011, p. 902).

Bakhtiar et al. (2013) conducted an archival statistical overview study to compare RE policies and FIT regimes between the Philippines and Indonesia for the period up to 2010. There are several key differences between the two FIT regimes. First, the Indonesian tariffs aim to promote small hydropower, biomass and geothermal energy, while the tariff mechanism in the Philippines promotes all renewables. Second, the FITs in Indonesia aimed only at small and medium-scale producers with a generation capacity of a maximum of 10 MW. Third, PPA contracts last 20 years in the Philippines, while fixed contract periods were not specified for hydropower and biomass energy producers in Indonesia. Finally, Indonesian FIT payment mechanisms are classified into various voltage classes and regional factors, while rates on the Philippines are fixed rates payable over fixed periods (Bakhtiar et al. 2013, p. 422).

3.4 Feed-in tariffs in Indonesia

Indonesia has experimented with price-based regulations to promote RE since the mid-1990s. These have undergone various changes over the past two decades. Strictly speaking, these regulations did not start out as FITs, as they did not specify exact tariff schedules. They evolved over time into FITs that contain specific purchasing prices for the utility PLN, but were still subject to negotiations between IPPS and PLN. Moreover, they were initially mainly aimed at small and medium hydropower producers but have gradually evolved to encompass other technologies (geothermal, biomass, waste-to-energy (WTE) and solar). The remainder of this chapter charts out this regulatory evolution, using the term FITs as a shorthand as understood in the above context.

3.4.1 Feed-in tariff regimes for small and medium power producers

In 1995, the Indonesian Government issued Ministerial Regulation (MR) No. 1895/1995 on the selling rate of electricity from small-scale power generating plants owned by private sector and cooperatives (see Appendix 3.2). The regulation did not state a specific price. Tariffs were based on PLN’s annually adjusted marginal production costs.

Negotiations on the tariffs also allowed for a host of other negotiable items, such as allowances for energy price changes or capacity factor multipliers.

In 2002, a new pricing regulation was issued in the shape of Ministerial Decree 1122/2002 (known as PSK Tersebar or Ministerial Decree on Small-Scale Power Purchase Agreement). The new price regulation specifically targeted small-scale producers—cooperatives, private companies or government-owned companies—with a generation capacity of up to 1 MW. Again, no specific price was stated, but the tariff was formulated as a percentage of PLN's BPP, grouped into voltage classes. Specifically, the electricity purchasing tariff was set at 60 per cent of PLN's production cost if connected to the low voltage grid or 80 per cent if connected to the medium voltage grid. Technically, this did not constitute a premium price to incentivise RE developers, given that the cost of renewables exceeded PLN's average production costs.

In 2006, the government followed up with an additional price regulation, MR No. 2/2006 on Medium Scale Power Generation Using Renewable Energy.[22] The regulation has a similar design as the 2002 MR but was targeted at medium-scale power plants. The maximum allowable capacity of each power plant is 1–10 MW. A purchase contract for 10 years or longer can be negotiated, also allowing for periodic price adjustments. Price adjustments were based on PLN's BPP, which are largely derived from costs incurred to fossil fuel power plants.

The government revised its RE pricing policy in 2009, when it issued MR No. 31/2009 on Small and Medium Scale Power Generation Utilizing Renewable Energy. This time, a specific purchasing price was stated in the regulation, 656 Rupiah/kWh. Under this regulation, PLN is obliged to purchase electricity from small and medium-scale private RE power plant developers such as cooperatives, community or business entities. Eligible power plants are those with a generation capacity of 1–10 MW. The price is regulated for medium, low voltage grid connections and the interconnection system and is determined by a regional f-factor.[23]

---

[22] The regulation is supported by Governmental Regulation No. 03/2005 on Electricity Supply and Utilization and its amendment Governmental Regulation No. 26/2006.

[23] For example, the base purchasing price of 656 IDR/kWh is multiplied by the f-factor if connected to a medium voltage grid, and 1004 IDR/kWh x f, if connected to low voltage grid. The f-value for the grid system is 1.0 in Java and Bali, 1.2 in Sumatra, 1.3 in Kalimantan/Sulawesi and 1.5 in Papua/Nusa Tenggara.

Another new feature of the 2009 regulation is that PLN was given the authority to base the purchasing price on its own electricity cost estimates. These estimates also needed be reported to the Minister of MEMR. In addition, PLN was also obliged to provide standardised PPA contracts.

Although the tariff under MR No. 31/2009 was valid for all RE technologies—including hydropower, biomass, solar and wind—a consensus among the RE industry emerged that the price was only suitable for hydropower development. When policymakers decided on the new FIT, the MEMR and PLN took on board policy recommendations and cost estimates based on studies submitted by RE industry circles, under the wings of Masyarakat Energi Terbarukan Indonesia (METI, Renewable Energy Society) (Interview 1 and Interview 2). However, the studies came up mainly with cost estimates of private hydropower developers and did not include other RE fuel sources. The MEMR used these as the main inputs to design MR No. 31/2009, much to the complaints of non-hydropower developers (Interview 2).

As a result, since 2010 the regulation has increased the number of approvals for PPAs of small and medium hydropower projects (SMHPPs), reportedly by around 200 (Interview 3). News reports also confirm a massive increase in signed hydropower PPAs, as PLN announced plans to buy power from 130 MHP plants, most of them outside Java and set to start commercial operation in 2013.[24]

Predictably, non-hydro RE project developers were not happy with the revised 2009 FITs. Specifically, biomass developers immediately started to lobby for prices more suitable for the various existing technologies in the industry and presented proposals to PLN and the MEMR (Winarno 2011). They argued that biomass prices are especially cost effective when compared to diesel fuel costs and lobbied for prices in the range of 1,100–1,200 IDR/kWh (Interview 1). Industry representatives also suggested that PLN's benchmark price for biomass was at least a base price of 900 IDR/kWh in 2010, based on PLN's purchase of electricity supplied biomass plants operated by PT. Growth Sumatra Steel Industry Ltd., a project developer in Makassar, South Sulawesi estimates that prices in the range of 1200 IDR/kWh outside the Java–Bali grid would create rates

[24] 'PLN to buy power from 130 micro-hydro plants', *Jakarta Post*, 23 February 2012.

of return in the range of 25 per cent, which is more than satisfactory for developers (Interview 4).

In February 2012, the MEMR issued MR No. 4/2012 on PLN Purchasing Price of Renewable Electricity from Small and Medium Size Producers (1–10 MW). The regulation confirms the tariffs set under MR No. 31/2009, but added FITs for biomass, biogas and municipal solid waste and sanitary waste. The tariffs are set in the range of 850–1080 IDR/kWh for medium voltage and 1198–1398 IDR/kWh for low voltage classes. As is the case with hydropower and other renewable fuel, these FITs are multiplied by the f-factor, which varies across regions.

A new stipulation is that if PLN decides to buy power in excess or equal to the prevailing production costs (BPP), it must seek permission from the Director General of Electricity of the MEMR. Moreover, PLN is obliged to report provincial BPP prices to the Director General of Electricity every three months.

However, another revision followed with the issuance of MEMR MR No. 19/2013, which specifically revised the FITs for electricity based on municipal waste conversion and landfill technology. When compared to the FITs under MR No. 4/2012, the FIT for municipal waste management (*Zero Waste Technology*) was increased by 38 per cent to 1450 IDR/kWh for medium voltage and by 29 per cent to 1798 IDR/kWh for low voltage. The FIT for *sanitary waste* technology-based power (*Landfill Technology*) was increased by 47 per cent to 1250 (medium voltage).

FITs for small and medium hydropower producers were revised again in 2014 via MR No. 12/2014 and again in 2015 via MR No. 19/2015. The revisions stipulated a two-phase tariff schedule in a 20-year PPA contract. PLN will purchase power from producers with different tariffs for years 1–8 and 9–20 (see Table 3.1). Comparing the hydropower FIT regulations, they increased substantially between 2009 and 2015 (see Table 3.1).

Table 3.1: Hydropower feed-in tariffs for small and medium power producers

Ministry of Energy and Mineral Resources regulation	Fixed rate		Years 1–8		Years 8–20	
	IDR	Cents	IDR	Cents	IDR	Cents
MR No. 31/2009						
Up to 10 MW	656	6.3				
Up to 250 kW	1,004	9.6				
MR No. 12/2014						
Up to 10 MW			1,075	9.1	750	6.3
Up to 250 kW			1,270	10.7	770	6.5
MR No. 19/2015						
Up to 10 MW			1,560	12.0	975	7.50
Up to 250 kW				14.40	1,170	9.0

Note: Average annual exchange rates for 2009: 10,380 IDR/USD; 2014: 11,862 IDR/USD; 2015: 13,000 IDR/USD.

Recognising the growing international competitiveness of solar PV, the MEMR issued MR No. 17/2013 to regulate FITs for solar PV power plant developers. The Ministry issued a capacity quota tender with 140 MWp of total capacity offered in 80 locations across the country. Each project was less than 10 MW. The FIT was a ceiling price in the range of 25–30 cents/kWh. If developers used local content of at least 40 per cent, then they receive a higher FIT of 30 cents/kWh. In addition, the regulation stipulates a reverse bidding mechanism, meaning that the lowest bid by developers wins (MEMR MR No. 17/2013; Interview 5).

However, in 2015, MEMR Regulation No. 17/2013 was overturned by the Supreme Court after local manufacturers argued that the regulation did not provide sufficient incentives for local content. As a result, the tender process was stopped. At the time the regulation became invalid, seven developers had won bids, amounting to a total of 15 MW in seven locations. Signed FIT were in the range of 18–25 cents/kWh. Only two plants have been approved to go ahead in 2016.

In 2016, the Ministry issued a new FIT regulation, MEMR MR No. 19/2016, regarding Power Purchase from Solar Photovoltaic Plants by PT PLN. FITs range from 14.5

cents/kWh in Java to 23 cents/kWh in Papua. In contrast to the previous regulation on the purchase of solar power, these FITs are not based on a reverse bidding mechanism, meaning that the bids of developers are evaluated based on non-price factors such as administrative, financial and technical capacity.

The nationwide total quota for generable solar energy is 250 MWp, with Java having the largest quota capacity at 150 MWp, and Papua and West Papua having the smallest quota capacity at 2.5 MWp each. The quota capacity will be offered gradually by PLN through several tender projects, in which PLN will determine the maximum quota capacity that can be bid for by solar plant developers. For a project with of more than 100 MWp quota capacity, each solar plant developer can only bid for up to 20 MWp of the quota capacity. For a project between 10 MWp and 100 MWp quota capacity, each solar plant developer can propose a maximum 20 per cent of the quota capacity. There is no limit for projects under 10MWp.

Regarding local content, the new regulation requires solar plant developers to comply with the minimum local content requirements as stipulated by Ministry of Trade and Industry regulations.[25]

3.5 Project implementation of small and medium power producers under various feed-in tariff regimes: Trends and issues

This section presents findings from interviews with stakeholders and secondary data obtained during field work from 2011–2012. Thus, the material perceptions and views on the effectiveness of the renewable FIT regulations until 2012. It focuses specifically on the effectiveness of MR No. 1122/2002, MR No. 2/2006 and MR No. 31/2009, as most of the SMPPs interviewed for this research and the case studies from the literature operated during this period.

3.5.1 Data sources and limitations

Several caveats need to be noted when discussing the data on SMPPs. One is that the *Annual PLN Statistics*, the main source for data in the power sector, does not contain

[25] See ASEAN Centre for Energy at http://www.aseanenergy.org/blog/will-new-feed-in-tariffs-allow-indonesian-solar-power-to-shine/.

detailed figures on how many SMPPs have connected to the PLN grid. The reason is that power projects with less than 10 MW do not have to be reported in the national planning process (RUPTL). Thus, realised numbers of SMPP projects tend to be added on an ad hoc basis and sometimes with differing dates on commercial operation dates (CODs).

Given the lack of reported statistics, not all of the SMPPs could be captured in this research. As noted in Chapter 1, which summarises all the RE programs in Indonesia, many small hydropower or biomass projects in the Green PNPM or DME programs might have connected to the PLN grid or might sell their excess power to other parties, but reliable data on this were not available at the time of the research.

The data compiled for this chapter represents the number of projects which have been confirmed as having connected to the PLN grid, either in presentations by PLN, MEMR and industry representatives or interviews with stakeholders (see Tables A1–A3 in Appendix 3.1). Data on two major groups are presented. SMPPs are grouped into those with smaller than 1 MW capacity (SMPPS < 1 MW) or those with between 1 and 10 MW (SMPPs = 1–10 MW). This allows for matching the trends with the FIT regulations.

3.5.2 Small and medium power producers (< 1 MW)

The data for SMPPs (< 1MW) are based mainly on information provided by IBEKA. The reason is that many of the small and medium hydropower projects with less than 1 MW capacity (SMHPPs < 1 MW) have been implemented with the help of IBEKA, an award-winning CSO devoted to grassroots empowerment using mini hydropower schemes. Thus, the statistics of SMHPPs below 1 MW are heavily skewed towards one major developer and do not characterise a multitude of players in the mini hydropower market. In total, 61 projects have been realised by 2011, but only eight non-IBEKA projects are among them (see Table A1 in Appendix 3.3).

IBEKA is a CSO specialising in community development by financing and implementing small hydropower projects (Interview 6). It has pioneered small hydropower development as a tool for rural economic development in Indonesia.[26] IBEKA managed to implement 53 projects generating 3.8 MW in the period 1992–2010. The generation

[26] Mrs Tri Mumpuni received the prestigious Ramon Mansasay Award, an Asian equivalent to the Noble Peace Prize, for her work.

capacity of individual projects is small, ranging from a minimum of 5 kW to a maximum of 224 kW and with one larger project of 2 MW (see Table A1 in Appendix 3.3).

Most of these projects operate on a non-commercial basis aimed at widening the resource base of villages and expanding economic development. IBEKA helps to provide initial feasibility studies based on the community's inputs and then tries to obtain the funds to finance the MHP plant. Most of these funds are grants, either from private or external donors, as this ensures that the community does not depend on loan arrangements and can manage the plant on its own in the longer-term (Interview 6).

Out of 53 projects, by 2011 only six were reported to have a PPA with PLN.[27] Tariffs agreed for these projects were in the range of 432 IDR/kWh to 1000 IDR/kWh (4.8–11 cents/kWh at 9000 IDR/USD).[28] They had to be negotiated individually with PLN, once it became clear in each case that the community wanted to sell the excess power to PLN. Usually, IBEKA would take the lead in those negotiations, as they have already established a good working relationship with PLN, despite their differing development approaches (Interview 6).[29]

3.5.3 Small and medium power producers (1–10 MW)

There are two main groups of realised projects—SMHPPs and biomass/WTE SMPPs.

Appendix 3.3 shows that within the SMHPPs there are 12 IPP projects, and 10 projects run by PLN under a loan program of the ADB. The data on the private IPPs has been compiled from various reports and interviews. Data on four SMHPPs and two biomass/WTE SMPPs have been obtained from field interviews and reports. The data on the remaining six IPPs have been obtained from secondary literature.

---

[27] These projects included Waikilosawah in West Sumatra in 1999; Ulu Danau in South Sumatera in 2005; Cinta Mekar in West Java in 2004; Curug Agung, West Java in 1995; Trawas in West Java in 2003; Krueng Kala in Aceh in 2006; Banyubiru Salatiga in Central Java in 2010 (Interview with Mr Iskandar, IBEKA and Ms Tri Mumpuni, Director of IBEKA).

[28] The highest tariff was 1000.4 IDR/kWh for the mini hydropower plant in Krueng Kalla, Aceh. This power plant was constructed in the aftermath of the Tsunami in 2005 and PLN was reportedly willing to pay a higher price in the wake of the reconstruction process (Interview with Mr Iskandar, IBEKA and Ms Tri Mumpuni, Director of IBEKA).

[29] In some cases, communities also presented an explicit interest to be connected to the grid, because PLN can help in maintaining their power plants (Interview with Mr Iskandar, IBEKA and Ms Tri Mumpuni, Director of IBEKA).

The ADB-sponsored PLN SMHPPs have been obtained from ADB data, UNFCCC reports on CDM project preparations and interviews. The PLN projects are included to show some comparison of tariffs and costs between IPPs and PLN.

Table A3 shows 12 realised biomass/WTE projects. These were mainly reported in recent PLN and industry presentations, complemented by detailed information from interviews with two IPPs. The majority of those (seven) constitute projects that sell excess power to PLN and are, therefore, not long-term projects. Five projects are IPs with PPAs.

3.5.4 Main trends

Table 3.2 shows the quantitative trends grouped into the three periods in which the FIT regulations were valid.[30] The first policy period marks the regime under MR No. 1895/1995. The second period is dominated by MR No. 1122/2002 and MR No. 2/2006. The third period starts with MR No. 32/2009 and the subsequent revised MRs, which have all mandated specific tariffs.

First, in terms of both number of projects (units of plants) and generation capacity, the third policy period has seen the bulk of the increase of SMPP investment. This suggests that investors responded well to the more detailed regulations that specified tariffs and were also differentiated across technologies and regions. Second, SMHPPs with less than 1 MW capacity represent the majority of projects in terms of numbers. Third, SMPPs (1–10 MW) in both hydropower and biomass sectors were barely existent in the first policy period (1995–2002) but increased markedly in the later periods. This suggests that the FIT regulations of 2006 and 2009 have provided incentives to investors. Fourth, the bulk of the SMPPs in the biomass/WTE sector have been implemented since 2010 and signed excess power contracts with PLN. These contracts are only limited to one year, per MR No. 4/2012. This suggests that PLN wants to be more flexible in its purchasing of excess power from IPPs and prevent being locked into long-term contracts. Fifth, given that the electricity generation sector has been open to IPPs and non-commercial private entities since the beginning of the 1990s, the market for SMPPs

[30] See Appendix 3.3 which shows the detailed numbers. These represent the number of projects which have been confirmed to have connected to the PLN grid.

in RE is still fairly small and relies heavily on external financing mechanisms (see Tables A1–A2 in Appendix 3.3).

The next section will investigate the experience in project implementation and the perceptions of SMPPs and policymakers to shed some light on the factors explaining the above trends.

Table 3.2: Realised SMPPs (1995–2013)

	1995–2002	2003–2008	2009–2013	1995–2013
SMHPPs < 1 MW				
Units	24	21	16	61
MW	0.7	2.6	1.4	6.7
SMHPPs 1–10 MW				
Units		5	15	20
MW		25	79	104
Total SMHPP				
Units	24	26	31	81
MW	0.7	27.6	80.4	110.7
Biomass/WTE SMPPs 1–10 MW				
Units	1	3	8	12
MW	5	13	45	63
Total SMPPs				
Units	25	29	39	93
MW	5.7	40.6	125.4	173.7

Notes: SMHPP = small and medium hydro power producer, WTE = waste to energy, SMPP = small and medium power producer,
Source: Tables A1 and A2, Appendix 3.3.

3.6 Case studies and stakeholder interviews

This section highlights the views on and the experience with the FIT regulations of several SMPPs and policymakers.

3.6.1 Small and medium hydropower projects (< 1 MW)

There is not much evidence that the 1995 FIT regulation (MR No. 1895/1995) was effective in making PLN purchase renewable electricity from SPPs on a large scale. Some observers argued that in the 1990s the first wave of large IPP projects in the electricity sector created a situation of excess supply of private power in the market. This made the purchase of RE supply from SMPPs less urgent for PLN and, thus, limited larger uptake of renewables (Seymour & Sari 2002).

Ferrey (2004) documents the failure of a major donor-funded RE project during the period governed by MR No. 1895/1995. In 1996, with the help of a rural electrification loan from the World Bank, PLN set up a program in which SMPPs could bid for electricity projects, but RE projects were given preference if the quality of the bids was the same between renewable and fossil fuel–based projects.[31]

One key constraint was that the provisions under the FIT regulation allowed PLN to treat the standardised PPAs as non-binding. This enabled PLN and the government to change original PPAs, which undermined the financial viability of the projects. Specifically, tariff-related amendments to previously accepted items were made, such as the removal of the price escalation clause, adding an allowance for energy price changes, or including capacity factor multipliers that effectively imposed capacity-related revenues and thus reduced the price paid to the SMPP. The perception among SPPs was that the revised project contracts have moved the balance of power to PLN (Ferrey 2004, pp. 38–39).

The prime example is IBEKA, a CSO specialising in community development by financing and implementing small hydropower projects (Interview 6). Observers noted that the existence of MR No. 1122/2022 owes much to the lobbying efforts of IBEKA (Interview 7).[32] There is some indication that the relative success of IBEKA projects has framed the mindset of PLN managers on how to implement mini hydropower projects. The experience with IBEKA projects showed PLN that many small-scale RE projects were interested in connecting to the grid to sell their excess power. In cases where these small developers decide to connect to the grid, PLN is able to offer a purchasing price lower than its own cost of electricity generation. According to representatives of PLN, the main

[31] If there were two project bids of equal quality, and both accepted the avoided cost price, then the renewable project was to be chosen (Ferrey 2004, p. 40).

[32] Interviews with Fabby Tumewa, Director, Institute for Essential Services Reform and Agus Sari, Green Capital. See also United Nations Economic and Social Commission for Asia and the Pacific (2012), 'Case study: Indonesia's micro hydropower projects' (http://www.unescap.org/esd/environment/lcgg/documents/roadmap/case_studyfact_sheets/Case%20Studies/Indonesia-Micro-Hydropower-Projects.pdf).

reason is that these small projects incur relatively low costs due to the small generation capacity and low-cost technology (Interview 3).

MR No. 1022/2002 seemed to be effective for community-oriented mini hydro power projects. IBEKA's Cinta Mekar mini hydropower project in West Java was among the first to be implemented in the wake of the 2002 FIT regulation. The 120 kW-capacity plant was constructed within two years and started to operate in 2004 (Interview 6).

Tumiwa (2010) document that there were several key elements that contributed to the success of the Cinta Mekar project. First, sufficient external financial support was available from the United Nations Economic and Social Commission for Asia and the Pacific. Second, community support was fostered through a participatory approach which also ensured the sustainability of the plant's operation beyond the official project life. Third, PLN was willing to pay the price of 432 IDR/kWh, which was deemed as a fair price by the community (Tumiwa 2010, p. 8). The remainder of this section deals with the effectiveness of MR No. 1122/2002, MR No. 2/2006 and MR No. 31/2009.

3.6.2 Small and medium hydropower power producer projects (1–10 MW)

Most interviewed SMPPS and case studies from the literature suggest that the FIT regulations were not very effective in guiding PLN and IPPs to quicker PPA agreements.

3.6.2.1 Issues directly related to the FIT regulations

One key reason is the lack of transparency regarding regional or national PLN production costs (BPP), which serve as benchmark cost information in the energy sector. MR No. 1122/2002 and the subsequent MR No. 2/2006 set the tariff at 80 per cent of PLN's production costs, which gives the utility ample room to negotiate final PPA prices, with the utility reluctant to provide full information on the BPP.

One IPP, PT Fajar Future Energi Luwur, experienced lengthy tariff negotiations and cited unclear benchmarking costs as one main reason for protracted negotiations (Interview 17). This IPP developed a small-scale hydroelectric power plant along the river at Ranteballa village in South Sulawesi. The length of the period between the feasibility study and reaching a PPA tariff agreement was two years.

The project developer stated that PLN did not provide any clear benchmark price for electricity produced in the region during the feasibility study period. It was also not clear whether the regional or the central PLN agencies were responsible for handling the project application, as the project developer had to go through various bureaucratic entities in both the Jakarta and regional PLN offices. Only in late 2006 was a PLN committee formed to handle the approval of hydropower projects, but even then, no fixed benchmark tariff for hydropower developers was announced (Interview 9).

Tariffs for the project were revised several times. In the initial feasibility report, completed in early 2005, the benchmark price was set at 432 IDR/kWh. This was based on information provided by PLN and based on PPA contracts with other IPPs. In March 2007, the signed PPA states a tariff of 469.7 IDR/kWh, 8.7 per cent higher than the original price (DNV 2010, p. 9). However, cost–benefit analysis prepared to apply for CDM financing shows that to reach a benchmark IRR of 11.72 per cent,[33] the tariff would have to be increased by 13.2 per cent to reach 489 IDR/kWh. However, the negotiated tariff fell short of that (Interview 9).

By 2011, the project developer stated that the current purchasing price should be set at 787 Rp/kWh in South Sulawasi, if one follows the 2009 FIT regulation MR No. 1/2009. This would mark another steep increase of 67 per cent. The project developer left it open whether he would try to renegotiate a higher tariff (Interview 9). In terms of financing, the project developers had successfully applied for funding using the CDM. Revenues from the sale of accredited CERs made the project attractive (Interview 9).

PPA negotiations between PLN and IPPs are characterised by the absence of clearly defined cost concepts. PT Bumi Investco Energy is a mini hydro developer with a portfolio of five projects. By mid-2011, it had implemented one project, a 9 MW plant in Simalungun, North Sumatra. Based on the experience with the Simalungan project, the project developer stated that negotiations on the PPA tariffs are protracted because PLN has to consider other objectives than affordability. As a result, there is a muddled application of cost concepts in negotiations, as PLN uses its discretion to determine which cost concept fits its interests. It seems unclear whether it uses PLN internal least

[33] This would be in line with the minimum average lending rate prevailing in Indonesia in 2005.

cost or regional average cost of its fuel supply mix as a basis for comparisons (Interview 10).

The project developer argues that the negotiation strategy of PLN is also guided by benchmarking prices (BPP) that are based on the latest completed PPA. For instance, if PLN has completed a PPA with firm A with a price of 500 IDR kWh, it is not likely that the utility will deviate much from this price in negotiations with firm B a few months later. It will use the 500 IDR as an inflexible benchmark, even if there are grounds for other projects to ask for a higher price. Moreover, there is also an institutional constraint for PLN, as the budget auditors KPK will ask whether it is justified for PLN to pay prices for fuel that are higher than its own BPP benchmarking costs (Interview 10).

Other contentious issues in PPA negotiations include different views on the assumptions used in the project proposals such as the exchange rate, inflation rate or fuel cost estimates. As a result of protracted PPA negotiations, project implementation has been slow. In North Sumatra, for instance, PLN has reportedly signed 20 PPAs with medium-scale hydropower project developers since 2006, but only two plants were constructed and operating by mid-2011 (Interview 10).[34]

In general, from the perspective of a private developer, PLN's incentives are still skewed by the government's policy to subsidise the utility. In the outer, remote islands, the utility prefers to purchase diesel-based electricity instead of buying from renewables, because the diesel retail price is subsidised by the government (Interview 8).

Since the 2006 regulations (MR No. 2/2006), PLN also made use of the stipulation that tariffs can be defined for certain periods and adjusted periodically. On the one hand, it left PLN with additional leverage to change key parameters and to adjust to cost trends. Some of the IPPs also used the possibility to negotiate different tariffs for several periods as a way to smooth out their cost structure. On the other hand, it can also undermine investor confidence if there is no standardised process of negotiating PPAs and if parameters (e.g., indexing tariffs to inflation or exchange rate assumptions) could easily be changed by PLN on a frequent basis (Interview 10).

[34] As of August 2011.

PT Inpola Elektroindo runs the Parluasan mini hydropower project, located in the Pantil and Rumban Lao villages in North Sumatra (DNV 2010). The project developer stated that the firm intended to start the project earlier in 2004 as part of the first wave of small and medium IPPs. However, the developer found that the price PLN offered to MHPs was generally too low at around 425 IDR/kWh when the project was planned. In subsequent negotiations, the officially agreed PPA tariff with PLN was 437 IDR/kWh (UNFCCC 2010a). The sensitivity analysis in the feasibility study showed that without the revenues from the CDM the tariff would have to increase by at least 32 per cent to 577 IDR/kWh to make the project viable (Interview 11).

However, the project developer argued that the FIT MR No. 2/2006 made it possible to negotiate a phased PPA price. Thus, the developer managed to agree with PLN on a PPA price of 878 IDR//kWh for the first five years of a 25 contract. The developer also commented that most IPPs that started their projects after 2009 were happy with the mandated price under MR No. 31/2009 (Interview 11).

Changes and revisions in the regulations slowed ongoing PPA negotiations and affected project implementation. One example is the 140 kW Wangan Aji plant in Wonosobo, Central Java. The DGEEU at the MEMR is the executing agency on behalf of the government, with the cooperative KOPONTREN assigned as the operator. Initially, PLN would only agree to negotiated prices without references to the BPP as prescribed in the guidelines under MR No. 2/2002. In subsequent negotiations, the utility agreed to use the guidelines and stated that its final delivery price (i.e., its supply cost or BPP) at the medium voltage interconnection, was 772.67 IDR/kWh. This resulted in a final PPA price of 616.13 IDR/kWh (= 0.8 x 772.67 IDR/kWh). However, the utility asked that the PPA contract had to be renewed annually, which is not mandated in the older FIT MR No. 1022/2002 (Kopenindo 2008, p. 16).

Differing legal interpretations over MR No. 1122/2002 and MR No. 2/2006 created uncertainties in project implementation. First, PLN’s understanding is that tariff negotiations should be between business entities (i.e., PLN and the KOPONTREN). However, if the government insisted that the tariff should be mandatory, then the MEMR must announce an official tariff first, which it has not done. Second, the stakeholder negotiations also revealed that government officials were unsure about the proper sequencing of obtaining the two main licences. PLN assumes that the Electricity Business Licence for Public Provision (IUKU) has to be issued to the IPP first before the PPA is signed, whereas the MEMR/DGEEU thinks that the reverse order is true (Kopenindo 2008, p. 17; Interview 6).

There is some evidence that MR No. 31/2009 offered a FIT that provides sufficient incentives for hydropower developers to implement projects quickly. One example is PT Selo Kencana Energi (SKE), a private developer that operated a 7.5 MW hydropower plant in the district of Solok Selatan (South Solok), West Sumatra (Interview 16). The project developer negotiated a PPA price of 770 IDR/kWh, which was higher than the mandated 656 IDR/kWh under the 2009 FIT regulation. In fact, SKE obtained a PPA for 25 years with PLN. In the first five years, the agreed price was 770 IDR/kWh (7.7 cent/kWh).[35] The price was 485 IDR/kWh (4.85 cents/kWh) from the sixth to fifteenth year, after which it was supposed to be reviewed again.

Although this negotiated tariff was higher than the FIT regulation, the project developer argues that this was an acceptable price for PLN. The reason was that the price for diesel in Sumatera was set at 3,000 IDR/kWh. If SKE offered a price of 770 IDR/kWh for electricity generated from hydropower, it was very affordable to PLN comparative to the cost of purchasing diesel. Moreover, even when compared to the price of coal, renewables were already competitive, as the coal price had increased significantly in recent years (Interview 8).

However, there was also evidence that FITs under MR No. 31/2009 were still below cost-recovery level and did not guarantee that developers could make the projects viable without external financing. One example is the Tarabintang SMHPP located in Siantar Dairi village (North Sumatra). This was a plant with an installed generation capacity of 10 MW (2x5 MW). The project was implemented by an IPP—PT Subur Sari Lasterich—and the electricity produced was to be connected to the North Sumatran grid. Carbon credits are managed by the firm Swiss Carbon Assets Ltd. The PPA was signed in August 2010 (UNFCCC 2012).

[35] Around 6.9–7.2 cents/kWh depending on the exchange rate range of 9,000–9,500 IDR/USD.

The PPA contract with PLN stipulated a tariff for two phases. The tariff for the first five years was 878 IDR/kWh and 714.32 IDR/kWh from year six until year 25 (UNFCCC 2012, p. 14). This fell into the mandated price range under the 2009 FIT. However, without the CDM revenues, the IRR benchmark rate was 13.2 per cent and the electricity tariff would have to be increased by 17.9 per cent to make the project viable. This is another example of existing FITs not presenting a price at which IPPs could sell automatically (UNFCCC 2012).

Finally, MR No. 31/2009 does impose additional costs on developers, as PLN now insists that the project developer must bear the costs of building the transmission line to connect the plant to the closest PLN grid. This was not the case in the period before 2009, in which PLN would build or pay the developer to build the line. Moreover, if there is a need for PLN to build an electrical relay station, then it becomes a negotiation issue, because it needs to be included in the annual RUPTL. In many cases, PLN does not have the budget to finance the transmission line or the relay station, which can slow down the implementation of the project (Interviews 10, 11).

3.6.2.2 General investment concerns

Several investment barriers were stated by developers.

In general, licensing requirements for energy projects are costly, as developers need to process at least 20 licenses. Overall investment costs for a hydropower project with less than 10 MW before the PPA has been signed is around US$400,000–500,000. The biggest cost is for the land acquisition and paying the consultants for the survey, feasibility study and engineering (Interview 10).[36]

Further, uncoordinated, government-internal approval processes cause uncertainties for project developers. Although developers are allowed to submit and process the documentation at regional government levels, PLN's internal coordination mechanisms seem unclear. Regional PLN authorities need feedback from PLN headquarters in Jakarta before they sign any project-related documents. Project developers like SKE argue that

[36] In the case of Bumi Investco Energy, engineering and surveys were costed at two billion Rupiahs or US$200,000. Overhead for pre-operating costs, including the costs for the licenses, were in the range of US$100,000–300,000 and then the entertainment for the licences.

they have to deal with regional offices first but have to follow-up with the central authorities in Jakarta in any case. In case of environmental permits—Uji Kelyakan Lingkungan Hidup—PLN must coordinate the issuance of permits with MEMR, which adds to the processing time (Interview 8).

These licensing costs can be especially high if developers must obtain permits to develop a hydropower plant in a protected forest area. The IPP must first obtain a permit to use the land in the protected forest area. Additionally, it must reforest the amount of the used land in another area approved by the Ministry of Forestry (MoEF). In the case of Inpola Meka Elektroindo, officials from the forestry estimated the number of trees and vegetation had to be make way for the power plant. The developer had to then pay a cash amount to the MoEF as the money necessary to reforest another area (Interview 11). The process of going through this process can last up to a year. It has to be processed in parallel with an environmental impact assessment document, the Upaya Pengelolaan Lingkungan, which is mandatory for projects with less than 50 MW of generation capacities. The process is cumbersome, as it involves obtaining assessments from various technical agencies under the MoEF which run across central, provincial and district levels (Interview 11).

In addition, the MoEF treats every project application as the same irrespective of the size of the land. In the view of one developer, there should be a special consideration for RE on land with less than 50 ha. It should be administratively easy to implement and would speed up implementation of mini hydro power projects. It could be done by letting local governments directly sign this permit. However, the project developer also acknowledges that there are some political constraints for this approach, as the central government is concerned about the rapid proliferation of these permits by powerful *Bupatis* (district heads) which could affect deforestation and land use management issues (Interview 10).

In general, IPPs face difficulties in accessing domestic funds. Business operates in a high-interest environment with lending rates averaging at an annual high interest rate of 13–14 per cent for project and corporate finance. Moreover, Indonesian banks only offer corporate finance, but no project finance. In the case of PT SKE, the developer has obtained project finance from donor-funded SMI facility. Other developers are in the more difficult position of having to apply for corporate finance. This is indicated by the fact that since 2005, 20 PPAs have been issued in North Sumatra, but no projects have been implemented as of 2011. Thus, the problem must lie in the capability of financing (Interview 8).

3.6.3 Donor-funded PLN mini hydropower projects

In 2002, the ADB approved a loan to PLN for RE development projects, which contained a significant proportion of mini hydro projects to be operated by IPPs. The loan came into effect in 2004 after delays in signing and aimed to be completed in 2008. The objective of the projects was to deliver about 82 MW of new generation capacity from RE-based sources and expand the distribution systems and connections by around 76,000 new customers. Specifically, 11 mini hydropower projects and two geothermal projects were to be constructed in Eastern Indonesia (see also Table A2 in Appendix 3.3).

However, implementation suffered from significant delays and the loan agreement of the project has been extended from the original closing date in September 2008 to September 2013 (Interview 12). As shown in Table A2 in Appendix 3.3, five hydropower projects have been implemented, four are expected to start in 2013 and the remaining two have been cancelled.

The slow implementation was mainly due to poor construction management and procurement problems. PLN requested more time to complete the projects. Moreover, the process of obtaining permits from the government to secure the construction of plants in protected forest areas proved to be difficult. Partly based on the experience with the RE development loan, the ADB had no plans to support new investment in mini hydropower plants (Interview 12).

Reports on the successfully implemented PLN projects show that external financing is necessary to fund the low tariffs (UNFCCC 2011, p. 31). The PLN-run mini hydropower plants in Lobong (North Sulawesi; 2x0.8 MW), Mongango (Gorontalo; 1.2 MW), Merasap (West Kalimantan; 2x0.7 MW) and Genyem (Papua; 2x 9.6 MW) use the CDM financing mechanism to make the projects viable. All projects show a final tariff of 4.25 cents/kWh.[37]

The financial analysis undertaken for the CDM application shows that without the revenues from the CERs the projects would be far below the benchmark IRRs (UNFCCC 2011a, UNFCCC 2011b, UNFCCC 2011c). For example, to make the projects sustainable, it would require an 88–172 per cent increase in the tariff over the carbon crediting period of seven years.[38] This means that PLN itself acknowledges that its own SMHPPs are only operational with an external subsidy. Moreover, the tariff of 4.25 cents/kWh would also not cover its own BPP/production costs at that time (UNFCCC 2011a, UNFCCC 2011b, UNFCCC 2011c).

3.6.4 Small and medium power producers in biomass and waste-to-energy technologies

Interviews with stakeholders reveal that MR No. 31/2009—stipulating a flat tariff for all renewables—is not suitable for non-hydro RE power projects. One example is the experience of IPP Bioguna Sustainable Power (BSP). BSP plans to construct and operate a rice husk–fired power plant in South Sulawesi (Interview 4). South Sulawesi produces approximately four million tonnes of rice grain per year and there are over 8,500 rice mills. BSP intends to source rice husk from the Bone and Pinrang regions of South Sulawesi and has approached 17 mills in Bone and 27 mills in Pinrang as potential suppliers (Interview 4).

The project developer stated that the prevailing mandated tariff under MR No. 31/2009 would not be viable to fund the project in all scenarios in the feasibility study. The mandated tariff would oblige PLN to buy any electricity produced at a maximum 853 IDR/kWh or 9.5 cents/kWh. The feasibility study concluded that a PPA price of at least 10 cents/kWh would have to be agreed with PLN to achieve an acceptable IRR (greater than 11 per cent) (Interview 4).[39]

---

[37] A report in 2001 based on the earlier feasibility studies recommended a tariff of 3.1 cents/kWh.
[38] Project lifetime is 25 years for all three projects.
[39] Base tariff of 656 IDR/kWh times the regional actor of 1.3 and an exchange rate of 9,000 IDR/USD. Sinclair Night Merz (SKM) was appointed by the International Finance Corporation (IFC), and carried out the feasibility study for BSP.

At the time of the interview, the project developer was in negotiations with PLN to secure a PPA that allows for periodic tariff adjustments. For instance, PLN could pay the developer a higher price of 1500 IR/kWh (16 cents/kWh) in the first five years, but a lower price of around 700–800 IDR/kWh (7–8 cents/kWh) afterwards. This would allow the developer to get better loan deals with local banks. In addition, the project developer was seeking to apply for CDM financing and had submitted a prior notification form to the UNFCCC by mid-2011 (Interview 4).[40]

The project developer confirmed that PLN tried to use tariffs from other projects as a benchmark for its negotiations with subsequent developers. In the case of PLN's discussions with BSP, the utility took a reference price of 900 IDR/kWh, because this was the PPA tariff they agreed to with another biomass energy developer, PT Growth Asia in Sumatra. But this price masks technological differences between the developers. Moreover, it can also be argued that PLN is guided by concerns about budget auditing, as the State Audit Agency (Badan Pengawas Keuangan (BPK)) might question PLN's rationale for allowing differing tariffs across IPPs (Interview 4).

The case of PT Navigat Organic, a landfill WTE developer, also illustrates the need for a technology-specific FIT, as MR No. 31/2009 proved inadequate.

An interview with the project developer suggested that arriving at an agreeable PPA tariff was a lengthy procedure. After the project developer won the tender, a feasibility study was carried out in 2008 and discussed with PLN. The discussions revealed discrepancies in the cost estimates between the IPP and PLN, with the former having to clarify its rationale underlying the financial analysis undertaken for the project. The financial parameters in the study had to be readjusted several times after consulting with PLN (Interview 13).[41]

The negotiations took around one and a half years from mid-2008 to 2010. During this period, the 2006 FIT regulation was initially the referenced regulation, but the 2009 FIT regulation also came into effect. The project developer stated that its estimate of an economic price for the project was 1200 IDR/kWh, but PLN offered to buy the electricity

[40] However, the project had not been registered at the UNFCCC website by end of 2013.

[41] For instance, the developer wanted to have an annual escalation clause of 3 per cent, which PLN refused.

at 680 IDR/kWh. The developer argued that PLN's rationale was flawed, as it was based on taking the 656 IDR/kWh mandated in the 2009 regulation and adding up a margin based on the utility's own internal judgement. PLN's calculations suggest that they were only willing to give the project an IRR of 14 per cent, but the project developer's view was that the IRR should be at least 15–16 per cent, given that the Indonesian interest environment is relatively high. Moreover, the banking regulation allows banks only to provide a loan with a maximum length of seven years (Interview 13).

In May 2010, the project developer and PLN agreed on a PPA tariff rate of 820 IDR/kWh or 9.1 cents/USD (with an exchange rate of 9000 IDR/USD). As the interview with the project developer suggests, this is still not an economic price for the developer. Moreover, at the time of the interview (the second half of 2011), the IPP was still waiting for the agreed tariff to be approved by the MEMR. The delay has caused some technical problems in early January 2011, as a large amount of unprocessed methane gas from the landfill has accumulated but has not been processed and converted into energy due to the uncertainty in regard to the final electricity price the IPP can charge. However, the developer anticipated that MR No. 31/2009 would be revised to mandate higher take up prices for PLN and that negotiating a higher price with PLN is still possible (Interview 13).[42]

Overall, the project developer argued that the problem lied with the monopsony of PLN, which allowed the utility to influence the price. The project developer argued that the problem with the MR 31/2009 regulation was that the mandated uniform tariff of 656 IDR/kWh simply did not take account of the technological differences between individual RE options. There were also structural barriers for landfill WTE projects, as the project size determined cost structures. For CDM suitability, at least around 400 to 500 tons per day of waste generation was necessary and this could only be achieved in large urban areas. Many small-size projects were not attractive for private investors. This implied different cost structures and investment needs and, therefore, there needed to a more sophisticated tariff schedule (Interview 13).

[42] Bisnis Indonessia, 16 January 2011, PLTSa Bantar Gebang Tunggu Izin Menteri ESDM, http://www.bisnis.com/pltsa-bantar-gebang-tunggu-izin-menteri-esdm.

Another problem was the overlapping administrative process that comes with dealing with several government authorities. The tender process was held by the local municipal government. The IPP had already signed a contract with the Jakarta municipality to construct and build the power plant with initial revenue and cost estimates. However, subsequent PPA talks with PLN required adjustments in their calculations. For instance, the IPP received revenues from the local government to process the waste in the form of a tipping fee. The size of that fee and the revenues for the IPP might have played a role in determining PLN's stance in PPA negotiations (Interview 13).

Financing for the project was obtained from Indonesian commercial bank Bank Panin, so the benchmark interest rate is the average nominal lending rate of 13.3 per cent in 2010.[43] The project developer was contemplating to obtain carbon financing via the CDM mechanism, but the administrative process was decided to be too long and costly and the consultants were too slow in handling the application. This created uncertainties as the banks were unsure whether the firm can get revenue from carbon credit. Thus, banks usually tended to exclude carbon credits from revenue streams of projects, which they viewed as too risky. Further, unlike in other countries where CDM projects are launched, registered projects can be not used as collateral in Indonesia. There is no regulation on this from Bank Indonesia (Interview 13).

3.7 Discussion: Key policy issues with the Indonesian feed-in tariff regime

How can the evolving Indonesian FIT framework be described when compared to the international experience? Table 3.3 shows several elements of a successful FIT design based on the experiences of various countries (Mendoncana, Jacobs & Sovacol 2009; IPCC 2011) and lists the equivalent Indonesian FIT regulations next to them.

Nominally, the Indonesian regulations do meet some of the key criteria of FITs. First, Indonesian FIT regulations do mandate PLN to purchase RE from producers. Second, the regulations have become more complex and specific over time, with tariffs becoming increasingly differentiated based on geographical location and technology. MR No.

[43] Interview in September 2011 with Agus Nugroho Santoso, PT Navigat Organic, who anticipated the new FIT regulation, which was issued in January 2012 as a MEMR MR No. 22/2012. See also 'Energy plans for Bekasi', *The Jakarta Globe*, 10 March 2009, and Tender Indonesia (http://www.tender-indonesia.com/tender_home/inner News2.php?id=8789&cat=CT0009).

31/2009 mandated a specific price for the first time, albeit a flat tariff for all RE technologies. Later regulations do provide technology- and location-specific tariffs. Third, long-term contracts have been a fixed part of the regulations. Fourth, tariff rates have been adjusted for phases in many of the regulations, usually splitting FITs into two periods.

Table 3.3: International best practice and Indonesian feed-in tariffs

	Indonesian FIT regulations											
Year	**1995**	**2002**	**2006**	**2009**		**2012**		**2013**		**2014**		**2016**
MEMR Regulation No.	**1895**	**1122**	**2**	**31**	**32**	**4**	**22**	**17**	**19**	**27**	**17**	**19**
Purchase obligation for utility	√	√	√	√	√	√	√	√	√	√	√	√
Differentiated tariff						√		√	√	√		√
Priority access and dispatch	√											
Duration of tariff payment			√	√	√	√	√	√	√	√	√	√
Periodic adjustment of tariffs			√	√	√	√	√	√	√			√
Transparent calculation and information on costs												
Streamlined administrative process (lead times)												
Clear legal status (law)										√*		
Financing based on pass-through to consumer												
Fiscal support mechanisms for RE technologies												

Sources: Based on Mendoncana (2009) and IPCC (2011: 902-903)

Note: * Only for geothermal sector, see next Chapter

However, some of the key criteria from international best practice are missing in the Indonesian case. Moreover, while the Indonesian FIT regulations nominally contain some of the core elements of a FIT, their implementation is a different matter, as seen in the previous discussion.

The interviews and case studies in the previous sections suggest that the FIT framework has not made PLN and SMPPs automatic price takers of renewable electricity, especially before the 2009 regulations. Many projects faced difficulties in quickly concluding PPAs to sell electricity to PLN. The negotiation process for the PPA raises transaction costs and these are further compounded by other investment-related regulations. In the following, the key emerging policy issues will be discussed.

3.7.1 Ineffective implementation of purchase obligations

The key issue here is that the FIT regulation does not provide a strong enough mandatory mechanism for PLN to take up renewables. While nominally PLN is obligated to take up RE from IPPs at the set prices, it still has the discretion to negotiate purchasing prices on a case-by-case basis.

Designed as purely price-based instruments, past and current FIT regimes are not linked to a quantitative target, which would require the utility to take up a certain quota of renewable electricity supply. Moreover, in 'best practice' countries such as Germany, FITs are also designed as independent of power demand. A purchase obligation independent of demand would mean that, for example, if the demand is low during a certain period, PLN as the grid operator would be obliged to reduce the amount of electricity from 'brown' sources and allow for 'green' power to be incorporated into the electricity supply mix. A quantitative target would provide investment certainty for RE producers, especially in monopolistic energy markets, where the grid operator also dispatches power generation capacity (Mendoncana, Jacobs& Sovacol 2009, p. 30).

3.7.2 Inadequate tariff levels

The literature suggests that setting adequate tariff levels is a question of politics, as opponents of RE will argue for low tariffs and supporters for the opposite. If FITs are set too low, they will not attract enough investors. If they are set too high, the FIT will undermine the efficiency of the FIT instrument, as society pays too much for renewable electricity (Mendoncana, Jacobs & Sovacol 2009, pp. 57–65).

Additionally, FITs work best when financing is guaranteed by a top up on the electricity bill of the final consumers (Mendoncana, Jacobs & Sovacol 2009; REN21 2011; IPCC 2011). In other words, they need to be backed up by a functioning price pass-through mechanism to distribute the costs among consumers and producers. Ideally, the government would act only as a regulator to oversee a system in which consumers pay a higher 'green' tariff—subsidised by the government—and the utility has an obligation to purchase electricity from the producer at the fixed price (Mendoncana, Jacobs & Sovacol 2009, p. 28).

In Indonesia, the incentive for the national utility is to set the tariffs at a low level and as ceiling prices to minimise expenditures. Set at maximum tariffs the FITs have also resulted in lengthy negotiations, as the case studies have shown. Moreover, the low tariff level offered by PLN has made it unattractive to IPPs to invest. In many cases where PPAs have been agreed, at least in the period governed by the FIT regulations in 2002–2012, successful project implementation was dependent on external financing. In another study comparing RE policies in the Philippines and Indonesia, Bakhtiar et al. (2013) found that the low FIT rates, combined with the absence of inflation in the calculation of the FIT rates, deter investment in RE projects.

However, in Indonesia the cost of the tariff cannot be easily passed on to the consumer, as consumer tariffs are subject to parliamentary approval and have been—until 2014—not cost reflective. For a long time, the cost of buying RE at the mandated tariff has only been passed on to PLN, which has had to rely on government subsidies to cope with that cost.

3.7.3 Incomplete information on PLN production costs and absence of technology-specific feed-in tariff rates

Incomplete information on electricity production costs (BPP) prevents the determination of accurate FITs. The literature suggests that FITs are meant to be price-based support instruments which allow for technology-specific support (World Bank 2011c). Additionally, the best way to calculate FITs is to use levelised generation costs to allow for technology-specific differences. This requires transparent information on production costs (Mendoncana, Jacobs & Sovacol 2009).

In Indonesia, for a long time, FITs have been designed in a way that ignored technology-specific differences. Before 2009, tariffs were set at a flat rate across various renewable technologies and were not specified and only recommended as a percentage of PLN average production costs (BPP). Moreover, PLN's BPPs have never been published on a regular basis, which made it hard for SMPPs to negotiate appropriate tariffs. Therefore, PLN is in a position to exploit the benefits of asymmetric information and dictate prices, as it is the largest single buyer in the domestic market.

Even before the 2009 regulations, which mandated specific tariffs, from the perspective of an IPP it was clear that negotiated tariffs were too low. The only time the government published the BPP rates was in 2008 under MEMR MR No. Regulation 269 - 12/26/600.3/2008 (see Table 3.4). It is apparent that PLN's revenues from the electricity tariffs did not match its supply costs. If one maps the reported negotiated PPA tariff from the case studies against these figures, it is clear that FITs under the pre-2009 regulations were too low.

Consequently, the lack of information on the true supply costs of electricity in the energy sector has led to flawed PPA negotiations, characterised by an absence of clearly defined cost concepts. The experience of some IPPs is that in negotiations PLN refers to various cost concepts or asks for changes to key parameters in PPAs. For instance, the utility does not only use levelised cost estimates but also refers to avoided or least costs or average cost of the regional fuel supply mix. Moreover, the negotiation strategy of PLN also seems to be guided by BPP based on the latest completed PPA, even if there are grounds for other projects to ask for a higher price.

This lack of transparent information underlying the FIT rates confirm findings in the literature. Bakhtiar et al. (2013) find that the FIT regime in Indonesia does not provide enough predictability for investors. Investors find it hard to calculate the returns of their projects if the government is not clear on providing enabling infrastructures or pursues inconsistent policies to support services to promote renewables (Bakhtiar et al. 2013, p. 422).

Table 3.4: Benchmark Electricity Production Costs (BPP) and Average Revenues (TDL) in 2008 (IDR/kWh)

Main grid system	Sub-system	BBT-TT	BPP-TM	BPP-TR	Avg. BPP	TDL
North Sumatra	Aceh	1,891	2,158	2,603	2,217	548
Sumatera	North Sumatera		1,984	2,306	2,145	602
	West Sumatera	565	790	878	800	578
	Riau		1,164	1,299	1,299	636
	South Sumatera, Jambi Bengkulu		696	783	783	617

Main grid system	Sub-system	BBT-TT	BPP-TM	BPP-TR	Avg. BPP	TDL
	Lampung		667	764	764	608
Bangka Belitung	Bangka Belitung		2,746	2,919	2,833	1,770
West Kalimantan	West Kalimantan	2,312	2,546	3,143	2,667	1,347
Central & South Kalimantan	South & Central Kalimantan	1,148	1,611	1,998	1,586	2,620
East Kalimantan	East Kalimantan	1,732	1,965	220	1,306	
North & Central Sulawesi	North & Central Sulawesi, Gorontalo	974	1,676	2,063	1,571	2,516
South &West Sulawesi	South Sulawesi, West Sulawesi	1,103	1,249	1,505	1,286	2,753
Maluku, North Maluku	Maluku, North Maluku		2,320	2,919	2,620	919
Papua	Papua		2,526	2,859	2,859	656
Nusa Tenggara Barat	Nusa Tenggara Barat		2,289	2,743	2,516	575
Nusa Tengara Timur	Nusa Tengara Timur		2,433	3,072	2,753	642
Java–Madura–Bali	Bali	783	859	1,012	885	686
	East Java		855	943	942	614
	Central Java, DI Yogyakarta		849	930	930	580
	West Java, Banten		853	939	939	599
	DKI Jakarta, Tangggerang		850	928	928	681
Indonesia average					1,649	1,027

Note: TR = Low Voltage; TM = Medium Voltage; TT = High Voltage.
Source: MEMR MR 269 - 12/26/600.3/2008.

3.7.4 Uncertain legal and political status of FIT regulations

The literature suggests that investment certainty is more secure if FIT schemes are entrenched into national law, and not merely established by MRs. Germany, for example, has enacted FIT laws since the 1990s to mandate that utilities connect RE producers to the grid. Other countries have also used public consultation to determine the FIT framework (Mendoncana, Jacobs & Sovacol 2009; IPCC 2011, p. 899).

In Indonesia, the legal status of FITs for SMPPs is uncertain and policymakers rely on a non-transparent process of legislating tariffs via MRs. Implementation of FITs is incoherent and a source of investment uncertainty. Some project developers have had to cope with different FIT regulations during project lifetime and managed to renegotiate an initial lower PPA price under the 2006 FIT and obtain a higher price from PLN under the 2009 FIT. This regulatory uncertainty gave PLN and IPPs more flexibility in negotiating terms of contracts, arguably putting the former in a better position to safeguard its financial interests.

While the prevailing FIT regimes and regulations created uncertainties on the ground, at the macro level it enabled lobbying by interest groups that succeeded in pushing for the instalment of improved and more sophisticated FITs. In Indonesia, the design of policies and instruments such as FITs is subject to a process of ad hoc negotiations between CSOs, industry groups and MEMR. Institutionally, the MEMR designs and drafts the regulations that affect the electricity and RE sectors. Interviews with stakeholders have shown that lobbying by interest groups has influenced policymakers in formulating regulations. In the 1990s, PLN did not take up RE projects under the terms of MR No. 1895/1995, as it changed PPA terms at will. MR No. 1122/2002 has been influenced and promoted by CSOs like IBEKA. Since 2009, industry groups and associations such as METI have actively lobbied for better FIT tariffs for SMPPs and geothermal producers (Interview 22). This has resulted in tariffs that have gradually increased over time. Moreover, industry lobbying has proven to be effective in negotiating more complex tariffs that are sensitive to cost differences due to technology-, site- and capacity-specific factors.

3.7.5 Regulatory conflicts and general investment climate

Streamlined and simple administrative processes are another ingredient of an effective FIT framework (IPCC 2011, pp. 902–903). Both geothermal producers and SMPPs reported difficulties in applying an accurate interpretation of certain aspects of the FIT regulations. This was the case with the pre-2009 regulations for SMPPs, when there was a lack of clarity on the proper sequencing of tariff announcement and the processing of the PPA and business licenses.

Overlapping administrative processes also provided a barrier to project implementation, especially in the case of processing forestry licenses, land permits, environmental impact assessments and fees in the WTE sector.

3.7.6 Lack of fiscal support mechanisms

The literature review in Chapter 1 suggests that fiscal policy instruments are effective when they are used in a complementary fashion with other regulatory and public investment types of instruments (IPCC 2011). Moreover, second-best policy conditions necessitate a combination of policy instruments (Labandeira & Linares 2010). Therefore, FITs may require both regulatory and fiscal actions, especially if there is commitment to achieve long-term RE targets. In the past, the generation costs for many RE technologies have been higher than coal and gas. Thus, it was necessary for governments to subsidise the proliferation of renewable electricity to close the gap (World Bank 2011c, p. 29). This can happen in the form of fiscal incentives like capital subsidies to fund high upfront costs, which are typical in the geothermal sector. Or they can be designed through state budget support or special funds to subsidise FITs (Mendoncana, Jacobs & Sovacol 2009; Castlerock 2011).

In Indonesia, there has been only a limited role for other fiscal policy instruments to support the FIT framework in both sectors. Stakeholders did not mention specific fiscal policy incentives that helped to facilitate their investment. In fact, there was no comprehensive fiscal policy incentive for renewables before 2010. The MoF issued MR No. 21/PMK.011/2010 on tax and customs facilities for RE resource utilisation activities. This regulation contained measures like income tax reductions, exemptions of VAT for machinery and exemptions from import duties.

3.8 Conclusion and outlook

This chapter has provided a historical analysis of the evolution and effectiveness of Indonesia’s FIT policies for SMPPs based on interviews with stakeholders in the RE sectors and developers of hydropower, biomass and WTE projects. The empirical analysis focused on the effectiveness of the regulations until 2012 but was complemented by a review of the literature covering regulations until early 2017.

From a design perspective, the Indonesian FITs are price-based instruments with no link to quantitative targets. Since the mid-1990s, the government has experimented with price-based regulations to incentivise RE supply from SPPs (< 1 MW) and SMPPs (1–10 MW). Initially, these regulations were not FITs in the strict sense, because they did not specify exact tariff schedules, and only later evolved into FITs that contain specific purchasing prices for PLN. Moreover, they were initially mainly aimed at SMHPPs, but have gradually evolved to encompass other technologies (geothermal, biomass, WTE and solar).

Qualitative evidence from stakeholder discussions show that PLN did not automatically take up renewables on a larger scale, despite existing FIT regulations. Most developers reported protracted PPA tariff negotiations with PLN, which has significantly slowed down implementation of projects, at least during the 2002–2012 period, the period for which most of the data originate.

The main reason for PLN's reluctance to take up renewables is that coal and gas have been cheaper than most renewables and, thus, have been the preferred options for PLN to generate electricity. Given that PLN—as the main buyer of electricity on the grid, acting de facto as a monopsony—has constantly faced budget deficits and relied on the subsidy to prop up its revenues, it naturally opted for the least-cost options. Past and existing FIT regulations have not been able to account for this and thus failed to sufficiently incentivise the utility to purchase more renewables and increase their share in the supply mix.

Evidence from the field research points to several design-related problems with the FIT regulations that worked against the proliferation of renewables and which are in line with findings in the literature.

At first, tariff levels were set too low to act as adequate incentives for IPPs and they did not constitute premium prices like in 'best practice' countries such as Germany. The Indonesian regulations either set the purchasing prices lower than the utility's BPP or, when later set at fixed prices, they proved to be too low for many developers or too high for PLN to automatically take up renewables. This has been exacerbated by the absence of regularly updated and transparent information on BPP which acts as benchmark production costs to serve as a guide for PPA negotiations. As a result, PLN is only willing to commit to ceiling (i.e., maximum) tariffs it deems to be in line with its—mostly internally-set—supply cost. Thus, in many cases PPA negotiations are slow and protracted, resulting in too low negotiated PPA tariff levels for projects, thus requiring external finance to be viable.

The lack of effectiveness of the FIT regimes is further accentuated by uncertainties associated with wider investment climate issues such as overlapping regulations and complex licensing processes. From a design perspective, the Indonesian FITs are price-based instruments with no link to quantitative targets. Since the mid-1990s, the government has experimented with price-based regulations to incentivise RE supply from SPPs (< 1 MW) and SMPPs (1–10 MW). These regulations were not initially FITs in the strict sense and only later evolved into FITs (i.e., contained specific purchasing prices). Moreover, they were initially mainly aimed at SMHPPs, but have gradually evolved to encompass other technologies (geothermal, biomass, WTE and solar).

Going forward, the key issue is that the FIT regulation does not provide a strong mandatory mechanism for PLN to take up renewables. Designed as purely price-based instruments, past and current FIT regimes are not linked to a quantitative target, which would require the utility to take up a certain quota of renewable electricity supply.

The literature suggests that in the absence of perfect market conditions, second-best policy conditions necessitate a combination of policy instruments. Therefore, Indonesian FITs may also require both regulatory and fiscal actions, especially if there is commitment to achieve long-term RE targets.

Appendix 3.1: Questionnaire and list of interviews

Section and themes	Content and questions
Introduction	• Disclosing information on PhD research • Objectives • Methods
Information about project	• Can you provide me with some general information about the project? (location, start of project; status of project development; costs of project preparation) • What is the financial/funding model of the project? • Does the project have a PPA agreement with PLN in place? How long is the contract? (Further questions on contract structure; etc.)
Perception on FIT regulations sector and the role of PLN in project development and implementation	• How long did it take to finalise the PPA? • Does the tariff under the PPA adhere to the prevailing FIT regulation? • Do you consider the tariff under the prevailing regulations as adequate? • Does the feed-in tariff provide sufficient incentives for developers enter the market to sell electricity to PLN? • How do you view the role of PLN in promoting renewable energy?
Perception on the general policy environment in the electricity and renewable energy sectors	• What is your assessment on the current and future role of renewable energy in Indonesia's electricity sector?
Other investment constraints	• Other than the FIT regulations, what are the major investment barriers for project development?
Closing	• Signing of consent form

Interview 1	Joko Winarno, Renewable Energy Society Indonesia; Masyarakat Energi Terbarukan Indonesia (METI)
Interview 2	Erwin Sadersa, METI
Interview 3	Hadi Susilo, Renewable Energy Division, PLN
Interview 4	Abianto, Project developer for PT BSP

Interview 5	Fenny Rahayu and Andri Suhindra, Staff Renewable Energy Division, Ministry of Energy and Mineral Resources (MEMR)
Interview 6	Tri Mumpuni and Iskandar, IBEKA
Interview 7	Fabby Tumewa, Director, Institute for Essential Services Reform
Interview 8	Jamsa Suwardi, Director, PT SKE
Interview 9	Robert Batara, PT Fajar Futura
Interview 10	Mohamad Assegaf, PT Bumi Investco Energi
Interview 11	Tiopan Marpaung, President Director, PT Inpola Meka Elektroindo (IME)
Interview 12	Bagus Mudiantoro, Project Implementation Officer, ADB
Interview 13	Agus Nugroho Santoso, President Director, PT Navigat Organic
Interview 14	Santoso, Association of Indpendent Power Producers
Interview 15	Alex Smillie, Senior Manager, STAR Energy
Interview 16	Alimin Gnting, Chevron and Indonesian Geothermal Association
Interview 17	Kurnia Rumdhony, Business Development Manager, PT Geodipa
Interview 18	Djoko Prasetyo, Head of System Planning, PLN
Interview 19	Anang Yahmadi, Head of Geothermal Division, PLN
Interview 20	Mohamad Sofyan, Head of Renewable Energy Section, PLN
Interview 21	Mike Crossetti, Castlerock Consulting
Interview 22	Rahman Mohamad, IPP Division, PLN

Notes: ADB = Asian Development Bank. IBEKA = Insitute for People’s Business and Economy. IPP = Independent Power Producers. METI = Renewable Society Indonesia. PLN = National Electricity Company. PT = Limited Liability Company. PT BSP = Limited Liability Company Bioguna Sustainable Power. PT SKE = Limited Liabliity Company SKE.

Appendix 3.2: Evolution and key features of feed-in tariff regulations for small and medium power producers in Indonesia

Year	Regulation	Key institutional features	Key PPA features	Key price features
1995	MR No.1895/1995 on the selling rate of electricity from small-scale power generating plants owned by private sector and cooperatives PLN prioritises purchase from hydro, wind, solar, geothermal. Small power producer defined as < 30 MW in Java and < 15MW outside of Java	Permits/Issued by: • SPPP (Notification of Presidential approval)/Chairman of Investment Coordinating Board (BKPM) • SPPM (Investment Approval Letter)/BKPM • IUKU (Electricity Business Licence for Public Provision)/Minister of MEMR	Contract for cooperatives: 1 year Contact for firms: 3–20 years PPA annulled after one year if firm cannot secure finance Letter of approval for project from DG of PLN basis for getting permits	No specific price Price based on: annual marginal cost of PLN and capacity factor
2002	MR No. 1122/2002 known as *PSK Tersebar* or on Small-Scale Power Purchase Agreement Requires PLN to purchase renewable electricity from producers for projects up to 1 MW capacity	Permits/Issued by (in addition to the ones in MD 1895/1995): • SULO (Commissioning Certificate)/DG PLN and district head • Letter of approval for project/DG PLN and head of district UPL/Ministry of Environment	Contract PLN has 60 days to evaluate project proposals Construction of plant must start within one year after signing of PPA	No specific price, price based on: • PLN production and delivery cost of electricity (BPP) • set as 60% and 80% of BPP for low or medium voltage connection

Year	Regulation	Key institutional features	Key PPA features	Key price features
2006	MR No. 2/2006 on Medium Scale Power Generation Using Renewable Energy for generation capacity of 1–10 MW	Same licences as MR No. 1122/2002	Minimum contract period: 10 years	Same tariff system as MR No. 1122/2002 No specific price Tariff for first three years based on BPP at the time of signing of PPA; afterwards annual adjustment based on annual BPP
2009	MR No. 31/2009 on Small and Medium Scale Power Generation Utilizing Renewable Energy Regulates and sets specific tariffs for small and medium power plants with capacity of up to 10 MW	Same licences as in previous MR PLN has the authority to base the purchasing price based on its own electricity cost estimates which needs to be reported to the Minister of MEMR	PLN is obliged to provide standardised PPA contracts	656 IDR/kWh (medium voltage grid) x regional f-factor (ranging from 1, 1.2 to 1.3) and 1004 IDR/kWh (low voltage grid) x regional f-factor Prices can be adjusted periodically
2012	MR No. 4/2012 on PLN Purchasing Price of Renewable Electricity from Small and Medium Size Producers (1–10 MW)	If PLN decides to buy power in excess or equal to the prevailing production costs (BPP), it has to seek permit from the DG of Electricity of the MEMR	For purchasing excess power, the maximum contract length is one year	Biomass and biogas: • medium voltage, 975 IDR/kWh • low voltage, 1,325 IDR/kWh Municipal solid waste:

Year	Regulation	Key institutional features	Key PPA features	Key price features
	Same as MR No. 31/2009, but adds tariffs for biomass gas, municipal solid waste and waste using sanitary landfill	PLN is obliged to report provincial BPP prices to the DG Electricity every three months		• medium voltage, 1,050 IDR/kWh • low voltage, 1,398 IDR/kWh Sanitary landfill waste: • medium voltage, 850 IDR/kWh • low voltage, 1,998 IDR/kWh
2013	MR No. 19/2013 on Purchasing Price of Renewable Electricity from Small and Medium Size Producers (1–10 MW) for municipal solid waste and landfill technology Revision of the purchasing price for municipal solid waste and landfill waste electricity for PLN as set under MR No. 2/2012	Same licenses as in previous MR	PPA length of 20 years	Municipal solid waste: • medium voltage, 1,450 IDR/kWh • low voltage, 1,798 IDR/kWh Waste using sanitary landfill: • medium voltage, 1,250 IDR/kWh • low voltage, 1,598 IDR/kWh
2013	MR No. 17/2013 on Purchasing Price of Renewable Electricity from Small and Medium Size Producers (1–10 MW) for Solar PV	Same licenses as in previous MR FIT part of reverse bidding mechanism Capacity tender quota managed by MEMR (140 MWp in 80 locations)	PPA length of 20 years FIT price includes connecting procurement fee to transmission to PLN grid	Developer bids, lowest FIT bid wins For local content modules (i.e., local content has to be greater than 40%): Year 1–10, 30 cents/kWh

Year	Regulation	Key institutional features	Key PPA features	Key price features
		Developer with lowest bid on FIT wins		Year 11–20, 13 cents/kWh For imported modules: Year 1–10, 25 cents/kWh Year 11–20, 10 cents/kWh
2014	MR No. 27/2014 on Purchasing Price of Renewable Electricity from Small and Medium Size Producers (1–10 MW) for municipal solid waste and landfill technology	Revised FITs of MR No. 19/2013		Medium voltage: • Biomass, 1,150 IDR/kWh • Biogas, 1,050 IDR/kWh • Municipal solid waste (zero waste), 1,450 IDR/kWh • Landfill waste, 1,250 IDR/kWh Low voltage: • Biomass, 1,500 IDR/kWh • Biogas, 1,400 IDR/kWh • Municipal solid waste (zero waste), 1,798 IDR/kWh • Landfill waste, 1,598 IDR/kWh FITS x regional factors, ranging from: Java (1) to Papua (1.6)
2014	MR No. 12/2014 Purchasing Price of Renewable Electricity from Small and			Base price x regional f-factor (ranging from 1, 1.2 to 1.3): Year 1–8:

Year	Regulation	Key institutional features	Key PPA features	Key price features
	Medium Size Producers (1–10 MW) for hydropower			Medium (up to 10 MW), 1,075 IDR/kWh Low (up to 250 kW), 1,270 IDR/kWh Year 8–20: Medium (up to 10 MW), 750 IDR/kWh Low (up to 250 kW), 700 IDR/kWh
2015	MR No. 12/2014 Purchasing Price of Renewable Electricity from Small and Medium Size Producers (1–10 MW) for hydropower		Regulation stipulates tariff in US cents/kWh	Base price x regional f-factor (ranging from 1, 1.2 to 1.3): Year 1–8: • Medium (up to 10 MW), 12 cents/kWh • Low (up to 250 kW), 14.4 cents/kWh Year 8–20 • Medium (up to 10 MW), 7.5 cents/kWh • Low (up to 250 kW), 9 cents/kWh
2016	MR No. 19/2016 Purchasing Price of Renewable Electricity from Small and Medium Size Producers for Solar PV	Quota capacity of 5000 MW determined on regional basis MEMR. Requires solar plant developers to	PPA length of 20 years	Fixed FIT on first-come-first-served basis Java (lowest FIT), 14.5 cents

Year	Regulation	Key institutional features	Key PPA features	Key price features
		comply with the minimum local content requirements as stipulated by Ministry of Trade and Industry regulations	FIT price includes connecting procurement fee to transmission to PLN grid	Papua (highest FIT), 23 cents

Notes: Asian Development Bank. IDR = Indonesian Rupiah. FITs = Feed-in-Tariffs. IPP = Independent Power Producers. METI = Renewable Society Indonesia. MEMR = Ministry for Energy and Mineral Resources. MR = Ministerial Regulation. PLN = National Electricity Company. PPA = Power Purchasing Agreement.

Appendix 3.3: SMPP project data

Table A1: SMHPPs below 1 MW									
Year	Source	Project	Province	Developer				PPA Tariff	Finance
COD		units		Cooperative	CSO	IPP	MW	IDR/kWh	
1992-2011	[1] [3]	53 projects across Indonesia			IBEKA		3.8	432-1000.4	GTZ, UNESCAP, ADB
									Local government
2003	[1] [2]	Seloliman	Central Java	PM Kalimaron	YBUL		0.03	425	GTZ , Bank Mandiri
2004	[7]	Kampung Melong	West Java	Koperasi P3TKEBT	GOI		0.109	432	GOI
2004	[15]	Kalimaron	East Java	Paguyuban Kalimaron			0.025		PPLH (GOI), GEF-SGP
2007	[8]	Anggrek Mekar Sari	West Sumatera			PT Anggrek Mekar Sari	0.668		GTZ
2008		Kalumpang	Central Sulawesi			PT Buminata Cita			
						Banggai Energy	1		World Bank
2004	[2] [15]	Dompyong	East Java	KUD Tani Tentren			0.04		GOI and Germany
2007	[14]	Wangan Aji	Central Java	KOPONTREN			0.14	618	ADB
2013	[6]	Santong	Nusa Tenggara Barat		PLN		0.85	n.a.	ADB
Total		**61**					**6.607**		

Table A2: SMHPPs 1-10 MW									
2007	[16] [17]	Mobuya	North Sulawesi			PT Cipta Daya Nusantara	3.0	420	BNI, Voluntary Carbon
2008	[5]	Hangga-Hangga	Central Sulawesi			PT Buminata Cita			World Bank
						Banggai Energy	2.5	n.a.	
2008	[2]	Telun Berasap	Jambi			PT Mambruk Saran	6.0	n.a.	Domestic private
						Interbuana	6.0	n.a.	
2008	[2]	Parlilitan	North Sumatra			PT Megapower Mandiri	7.5	n.a.	Domestic private
2010	[6]	Merasap	West Kalimantan		PLN		1.5	382 (4.25 cents)	ADB
2010	[6]	Lobong	North Sulawesi		PLN		1.6	383 (4.25 cents)	ADB
2009-13	[6]	Poigar 2	North Sulawesi		PLN		2.3	384 (4.25 cents)	ADB
2009-13	[6]	Mongango	Gorontalo		PLN		1.2	385 (4.25 cents)	ADB
2009-13	[6]	Prafi	Papua		PLN		1.6	n.a.	ADB
cancelled	[6]	Tatui	Papua		PLN		1.2		ADB
cancelled	[6]	Amai	Papua		PLN		1.1		ADB
2011	[6] [9]	Genyem 1	Papua		PLN		9.6	385 (4.25 cents)	ADB
2011	[6] [9]	Genyem 2	Papua		PLN		9.6	385 (4.25 cents)	ADB
2009-13	[6]	Ndungga	Nusa Tenggara Timur		PLN		1.9	n.a.	ADB
2011	[11]	Simalungan	North Sumatera			PT Bumi investco energi	9.0	700	Private, Domestic Bank
2013	[12]	Ranteballa	South Sulawesi			PT Fajar Future Energi Luwur	2.4	469	Private, IFC , Norway
2010	[1] [2]	Ponggang	West Java		IBEKA		2.0		External; Domestic bank
2013	[4]	Solok	West Sumatera			PT Selo Kencana Energi	7.5	770	
2014		Tarabintang	North Sumatra			PT Subur Sari Lasterich	10.0	878	CDM, domesti private
2011		Tangka/Manipi	South Sulawesi			PT Sulawesi Minihydro	10.0	469	CDM, domestic private
2011	[10]	Parluasan	North Sumatra			PT Inpola Meka	4.6	437	CDM, domestic private
						Elektroindo	4.2		
Total		**21**					**104.0**		

Table A3: Realised Bioenergy Projects (Power Purchased by PLN)

COD	Source	Company	Contract	Location	Type of Biomass	Capacity (MW)	Finance
2001	[19]	PT Riau Prima Energy	Excess power	Riau	Palm waste	5	Domestic
2006	[20]	PT Listrindo Kencana	IPP	Bangka	Palm waste	5	External: CDM, Denmark, Japan
2006	[19]	PT Growth Sumatra	Excess power	Sumatera Utara	Palm waste	6	Domestic
2006	[19]	PT Indah Kiat Pulp & Paper	Excess power	Riau	Palm waste	2	Domestic
2010	[19] [22]	PT Belitung energy	IPP	Belitung	Palm waste	7	Domestic: SOE
2010	[19]	PT Growth Sumatra	Excess power	Sumatera Utara	Palm waste	9	Domestic
2010	[19]	PT Pelita Agung	Excess power	Riau	Palm waste	5	Domestic
2010	[19]	Permata Hijau sawit	Excess power	Riau	Palm waste	2	Domestic
2011	[21]	PT Navigat Organic	IPP	Bali	Municipal solid waste	2	Domestic Bank
2011	[21]	PT Navigat Organic	IPP	Bekasi	Municipal solid waste	8	Domestic Bank
2011	[19]	PT Growth Asia	Excess power	Sumatera Utara	Palm waste	10	Domestic
2011	[23]	PT Bioguna Sustainable Power	IPP			2	External: CDM; Domestic Bank
		Total on-grid capacity				63	

Sources for Tables A1 - A3
[1] Interview with Iskandar and Tri Mumpuni, IBEKA
[2] Hardjomuljadi and Siswojo (2008)
[3] IBEKA website at http://ibeka.netsains.net/our-projects/catalog-of-projects/
[4] Interview with Abianto , Director of (SKE)
[5] UNFCCC (2011:18) PDD Manipi
[6] Interview with Bagus Mudiantoro, ADB and ADB (2013). 34100-013 Project Development Sheet Renewable
Energy Loan (updated Sepember 2013) at http://www.adb.org/projects/34100-013/details
[7] PLTMH Kampung Melong at Tender Indonesia http://www.tender-indonesia.com/tender_home/
innerNews2.php?id=7468&cat=CT0009
[8] Indonesia Small Hydropwer Plant Salido kecil at http://www.entec.ch/entecweb/
index.php?option=com_content&task=view&id=32&Itemid=33&lang=en
[9] UNFCCC (2011a). Project Design Document (PDD) Genyem PLN Hydropower Project.
[10] DNV (De Norske Veritas) (2010). Validation Report: Parluasan Hydroelectric Power Plant. Report No. 2010-9060.
Veritasvn, Hovik: Norway
[11] Interview with Mohamad Assegaf, President Director of Bumi Investco Energi
[12] Interview with Robert Batara, Director of PT Fajar Futura Energi
[13] UNFCCC (2012). Project Design Document (PDD) Tarabintang 2x5 MW Minihydro Power Plant
[14] Kopenindo and ADB (2008). Wangan Aji Micro Hydropower Project – Final Report. Report submitted to
to ADB Poverty and Environment Program, June 2008.
[15] UNFCC (2010). Project Design Document (PDD): Parluasan Hydro Electric Power Plant. Document version 5 04/11/2010
[16] VCS (Voluntary Carbon Standard (2009). Project Description: Mobuya Mini Hydro
Power Plant 3 x 1000 kW North Sulawesi, Indonesia.
[17] UNFCCC (2010a) Project Desgin Document (PDD): Parluasan Mini Electric Hydropwer Plant
[18] UNFCCC (2011b). Project Design Document (PDD): 10 MW Tangka/Manipi Hydro Electric Power Plant.
[19] Hutapea, Maritje (2012)
[20] TUV Sued Industry Service (2008)
[21] Interview with Agus Nugroho Santoso, Director PT Navigat Organik
[22] Bangka Pos 13/4/2010 PLTU Belitun Energy Jadi Pilot Project PLTU Biomassa
http://bangka.tribunnews.com/2013/04/13/pltu-belitung-energy-jadi-pilot-project-pltu-biomassa
[23] Interview with Abianto, Director PT SKM

Chapter 4: The Evolution and Effectiveness of the Indonesian Feed-in Tariff Regime in the Geothermal Sector

Abstract

This chapter provides an analysis of the geothermal policy framework, focusing on three aspects. First, it provides an historical analysis of the policy and regulatory framework governing the geothermal sector since the 1990s. Second, based on interviews with geothermal IPPs and policymakers, the chapter present the key issues and challenges associated with the implementation of the geothermal FIT regulations, focusing on the period 2009–2015. Third, the chapter presents an intuitive economic analysis to capture the effects of the Indonesian FIT regime—both for the geothermal IPPs and SMPPs—on the supply of RE in the Indonesian electricity sector.

The chapter finds that FITs have only really played a role since 2009 as part of a broader, complex regulatory and investment climate context. Like in the case of the FIT regulations for SMPPs, the design of the geothermal FIT instrument is deemed ineffective by most stakeholders due to a mix of inadequate tariff levels, PLN's preference for fossil fuel options, and wider regulatory and investment climate risks. Moreover, uncertainties also arise due to the unclear relationship between the geothermal FIT price and a competitive tender mechanism, which results in lengthy negotiations between PLN and geothermal producers.

4.1 Introduction

Given Indonesia's rich geothermal potential, the development of the sector has been regarded as being crucial to producing large-scale RE supply. Estimates of total national geothermal potential vary, but officially accepted estimates range between 27,000–29,215 MW (ADB & World Bank 2015, p. 2). Under the FTP 2 (see Chapter 2), the government targeted almost 5,000 MW of additional generation capacity between 2010–2014. However, an influential study provided a reassessment of 50 geothermal working areas (GWAs) and significantly reduced the realistic potential that could be developed in the short term to 2,270 MW (Castlerock 2011). The MEMR then issued a target of 5,817 MW to be installed by 2020, while the World Bank put the figure at 4,400 MW.

Total installed geothermal generation capacity stood at 1,439 MW in 2015 (PLN 2016), a relatively small amount compared to the total estimated resource potential. In fact, only 215 MW of geothermal generation capacity was added in 2010–2014, the period of the FTP 2. Thus, despite ambitious official targets, implementation and realisation of geothermal projects proceeds at a slow pace. Taking account of this implementation record, recent targets have been revised downwards, with the 35 GW program aiming to install an additional 725 MW by 2019 (PLN 2016).

Against this background of slow progress, this chapter continues the historical analysis on the effectiveness of the Indonesian FIT regime by looking specifically at the geothermal sector. Interviews with representatives from three geothermal power producers and various stakeholders in the energy policy community were conducted during 2011–2012. Together with a review of the regulations and secondary literature, they capture the perception and views on MR No. 32/2009 and the discussions leading up to the revised FIT regime under MR No. 22/2012 (see Appendix 4.1 for list of interviews). Analysis of the policy changes and new regulations after 2012 are based on a desktop review of the regulations and secondary literature.

Section 4.2 provides an overview of the policy and regulatory framework governing the geothermal sector since the 1990s and finds that FITs have only really played a role since 2009 as part of a broader, complex regulatory context. Section 4.3 reports on the main issues emerging from interviews with stakeholders in the geothermal sector. As in the case of SMPPs, the design of the geothermal FIT instrument is deemed ineffective by most stakeholders due to a mix of inadequate tariff levels and wider regulatory and investment climate risks in the sector. Section 4.4 provides a more systematic economic analysis to capture the core dilemma of the Indonesian FIT regulations for both geothermal IPPs and SMPPs: mandated tariff levels are not set at a premium rate high enough to attract most IPPs, while at the same time PLN perceives the prevailing FITs as too costly when compared to cheaper coal-based generation options. If increasing renewables is a serious goal for policymakers, then the effectiveness of a price-based instrument like a FIT could be strengthened by a mandatory quantitative RE target for the utility. Section 4.5 concludes and summarises the main policy implications.

4.2 Geothermal laws and feed-in tariffs

FITs for geothermal producers were legislated in 2009 and revised in 2012 and 2014. The first geothermal FIT regulation, MR No. 32/2009, is an implementing government regulation (GR) as part of Geothermal Law No. 27/2003. That law and its accompanying regulations represent the first standalone legal framework for a RE source. Preceding regulations had put the national oil and gas company PERTAMINA in charge of geothermal development. Table 4.1 lists all relevant regulations under the geothermal policy framework and describes their main functions. The timeline shows that it took several implementing regulations to be enacted between 2003 and 2009 to make the Geothermal Law fully operational. The framework under the Geothermal Law reveals a complex and lengthy project implementation cycle for developers. Figure 4.1 is a flow diagram based on the listed regulations in Table 4.1 and shows the project implementation process for a geothermal IPP.

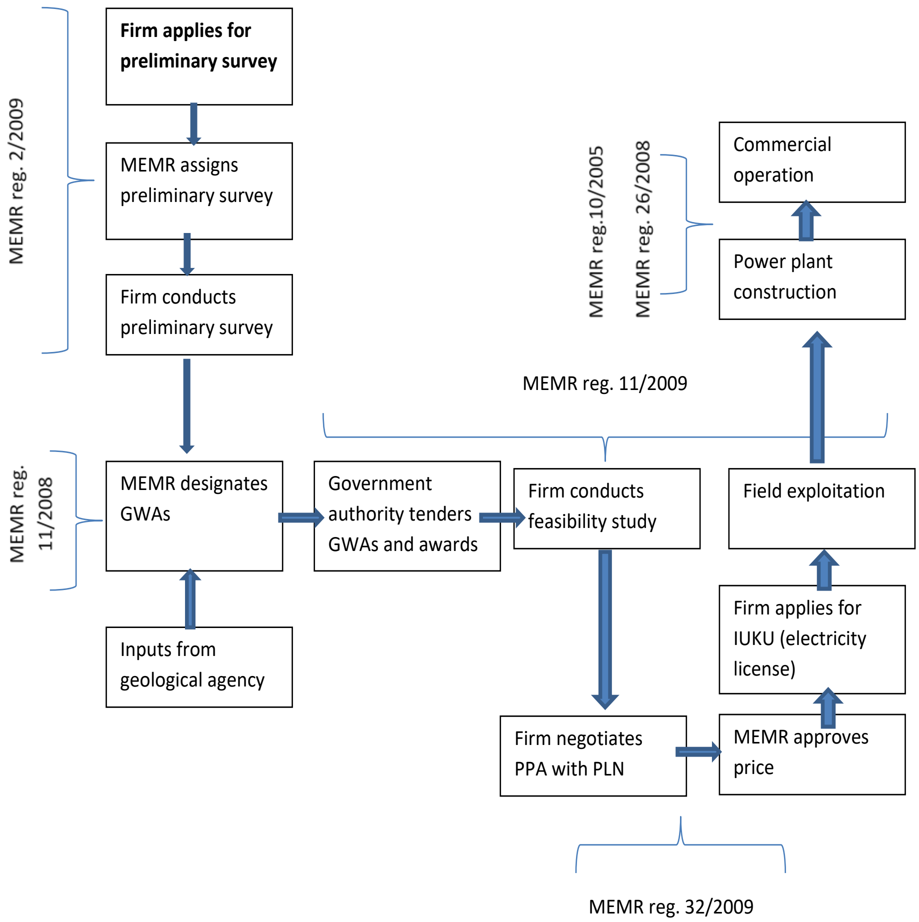
In the preliminary stage, the MEMR assigns firms to undertake preliminary surveys of prospective fields (MEMR MR No. 2/2009). The MEMR then designates the GWAs by taking inputs from the Geological Agency (MEMR MR No. 11/2008). In the tendering stage, the government tenders the GWA, and prospective IPPs bid. The tender can be conducted by the central or the provincial government if the GWA is located across one province or by district governments if the area is located within one district. After the GWA is awarded, the IPP can explore the GWA during a maximum of four years, with the feasibility study is to be finished within two years. The exploitation of the field can be done for 30 years and can be extended for an additional 20 years (MEMR MR No. 11/2009). Based on the feasibility study, the IPP will then negotiate with PLN to reach a PPA.

The purchasing price of electricity by PLN was determined by MEMR MR No. 32/2009, revised by MEMR MR No. 22/2012. Once the PPA has been negotiated, the MEMR has to approve the final price.[44] The IPP then applies for an IUKU (as stipulated by Electricity Laws 30/2009 and 15/1985). In the final stage, construction and commercial operations will be carried out.

In 2014, Geothermal Law No. 27/2003 was revised, and a new Geothermal Law No. 14/2014 was legislated. Several key changes were introduced. First, the new law allowed geothermal exploration and exploitation in protected forests. Second, the tendering authority was transferred from local to central government. Third, MEMR MR No. 17/2014 set FITs as ceiling prices based on avoided cost. This regulation constitutes the most comprehensive and differentiated FIT regime to date, with prices based on location-specific criteria and project starting dates (COD) cost (Asian Development Bank & World Bank 2015).

[44] The official project implementation cycle for all IPPs takes a minimum of 321 days, including all stages from pre-qualification to the final PPA. As geothermal projects have different tender regulations, the PPA negotiation with PLN itself takes a minimum period of 110 days for geothermal IPPs (PLN 2011, p. 14).

Figure 4.1: The geothermal project implementation cycle



Notes: MEMR = Ministry of Energy and Mineral Resources, PPA = purchase power agreement, GWA = Geothermal Working Areas, PLN = Perusahaan Listrik Negara.
Source: Adapted from Castlerock (2010, p. 38).

Table 4.1: Evolution and key features of geothermal laws and feed-in tariff regulations in Indonesia

Year	Regulatory instrument	Issues
1981	PD 22/1981	• Sole authority of PERTAMINA to explore and exploit fields and sell power to PLN and other bodies • Establishes JOCs (Joint Operation Contracts) to allow cooperation PERTAMINA and private field developers
1991	PD 45/1991	• Replaces PD 22/1981 • PERTAMINA and JOCS contractors can either (i) only develop steam field only and sell stream to PLN and IPPs for generation or (ii) develop steam and generate electricity to sell to PLN and other bodies
1991	PD 49/1991 MR (Finance) 799/KMK.04/1992	• Taxation of PERTAMINA and JOC contractors • Tax rate of 34% applicable to net operating income (NOI), but VAT is reimbursed by government • PERTAMINA entitled to 4% of NOI • Net profit for JOC of 64% of net operating revenues
1998	MR No. 209/KMK.04/1998	• Revises MR 799/1992 • Government reimburses VAT payment to JOC after contractor has paid government portion
2000	PD 76/2000	• Replaces MR 209/1998 • Increases tax rate to normal income tax level of 47% • Proposes that government undertakes all aspects of exploration and development
2001	Law 22/2001 on Oil and Gas sector	• Replaces Law No. 44/1960 • Geothermal development removed from jurisdiction of oil and gas regulation – necessitating new Geothermal Law.

<table>
<tr><th>Year</th><th>Regulatory instrument</th><th>Issues</th></tr>
<tr><td>2003</td><td>Geothermal Law No. 27/2003</td><td>End of PERTMMINA monopoly in geothermal development
Allows private sector control over geothermal resources and sale of base load electricity to PLN
Governor or local governments issue geothermal mining licenses (IUPs)
Defines geothermal work areas (GWAs (or WKPs in Indonesian)) which have to be tendered</td></tr>
<tr><td>2005</td><td>MEMR MR No. 10/2005</td><td>Regulates the construction and commercial operation of plants</td></tr>
<tr><td>2007</td><td>MEMR MR No. 59/2007</td><td>Regulates tender process</td></tr>
<tr><td>2008</td><td>MEMR MR No. 11/2008</td><td>Regulates procedures determining GWAs</td></tr>
<tr><td>2008</td><td>MEMR MR No. 26/2008</td><td>Regulates the construction and commercial operation of plants</td></tr>
<tr><td>2009</td><td>MEMR MR No. 2/2009</td><td>Guidelines for preliminary survey assignments</td></tr>
<tr><td>2009</td><td>MEMR MR No. 11/2009</td><td>Implementing regulation specifying guidelines for geothermal business operations</td></tr>
<tr><td>2009</td><td>MEMR MR No. 32/2009</td><td>Feed-in tariff for geothermal power set at 9.7 c/kWh</td></tr>
<tr><td>2012</td><td>MEMR MR No. 22/2012</td><td>Revised Feed-in tariffs differentiated based on regions (US c/kWh)
<table>
<tr><th></th><th>High voltage</th><th>Med. voltage</th></tr>
<tr><td>Sumatera</td><td>10</td><td>11.5</td></tr>
<tr><td>Java, Madura, Bali</td><td>11</td><td>12.5</td></tr>
<tr><td>Sulawesi (South, West, Tenggara)</td><td>12</td><td>13.5</td></tr>
<tr><td>Sulawesi (North, Central, Gorontalo)</td><td>13</td><td>14.5</td></tr>
<tr><td>NTB and Timur</td><td>15</td><td>16.5</td></tr>
<tr><td>Maluku and Papua</td><td>17</td><td>18.5</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Year</th><th>Regulatory instrument</th><th>Issues</th></tr>
<tr><td>2014</td><td>Geothermal Law No. 21/2014</td><td>Geothermal activities not classified as ‘mining’ activities anymore
Geothermal Business License now issued by central government</td></tr>
<tr><td>2014</td><td>MEMR MR No. 17/2014</td><td>Differential feed-in tariffs (cents/kWh) based on working areas and planned starting date of operations
GWA 1: Sumatera, Jawa dan Bali
GWA 2: Sulawesi, NTB, NTT, Halmahera, Maluku, Papua dan Kalimantan
GWA 3: Geothermal working areas in isolated areas in GWA 1 and 2 and which rely mostly on diesel.
<table>
<tr><th>COD</th><th>GWA 1</th><th>GWA 2</th><th>GWA 3</th></tr>
<tr><td>2015</td><td>11.8</td><td>17</td><td>25.4</td></tr>
<tr><td>2016</td><td>12.2</td><td>17.6</td><td>25.8</td></tr>
<tr><td>2017</td><td>12.6</td><td>18.2</td><td>26.2</td></tr>
<tr><td>2018</td><td>13</td><td>18.8</td><td>26.6</td></tr>
<tr><td>2019</td><td>13.4</td><td>19.4</td><td>27</td></tr>
<tr><td>2020</td><td>13.8</td><td>20</td><td>27.4</td></tr>
<tr><td>2025</td><td>15.9</td><td>23.3</td><td>29.6</td></tr>
</table>
</td></tr>
</table>

Notes: PD = Presidential Decree, MR = Ministerial Regulation, MEMR = Ministry of Energy and Mineral Resources, GWA = Geothermal Working Area, COD = commercial operation date.
Source: Various Laws and Regulations Issued by the Government of Indonesia.

Table 4.2: Geothermal Working Areas (GWAs), old legacy GWAs (as of 2011)

No.	Areas (GWAs)	Operated by			Contract (Date/price cents/kWh)		MW
		Original operator	Current operator	Status	Original	Renegotiated	
1	Darajat	Amoseas (joint chevron)	Chevron Geothermal Inc	IPP	1994 (6.95)	2000 (4.2)	255
2	Dieng	Himpurna/CalEnergy	Geodipa	SOE	1994 (9.81/7.41/6.21 over 30 years)	2000, 2006 (4.45–5.0)	60
3	Kamojang	PGE	PGE	SOE	1984 (SSA) 1994 (SSA)	na	200
4	Lahendong	PGE	PGE	SOE	1999 (SSA)		40
5	Salak	Unocoal Geothermal Indonesia	Chevron Geothermal Inc	IPP	1993 (7.6/5.75/5.21)	1997 (4.45)	330
6	Sibayak	PT Dizamatra Powerindo	Same	IPP	1996 (7.1)	2006 (4.7)	2
7	Wayang Windu	Mandala Nusantara/Brierley Investments	Star Energy	IPP	1994 (8.39/6.52/5.58)	2000 and 2006 (4.45–6.0)	227
8	Bedugul, Bali	Bali Energy Ltd./CalEnergy subsequent Mid-American Energy	PGE	SOE	1995 (7.15)	na	175
9	Cibuni	PT Yala Teknosa Geothermal	PLN		1995 (6.9)	na	2
10	Karaha	Caithness Corp/Florida Power	PGE	SOE	1994 (7.6/5.75/5.21)	Alstrom COD 2016	30
11	Patuha	CalEnergy	Geodipa	SOE	1994 (7.26/3.48) over 22 yrs)	2006, 2007 (4.45–5.0)	55

No.	Areas (GWAs)	Operated by			Contract (Date/price cents/kWh)		MW
		Original operator	Current operator	Status	Original	Renegotiated	
12	Sarulla	Unocoal Geothermal Indonesia	Sold to PLN then Geodipa then to Medco Energi 2007	IPP	1993 (7.6/5.75/5.21)	2007 (4.7) 201 planned (7.0)	330
13	Lumutbalai	PGE	PGE	SOE	na	na	110
14	Ulubelu	PGE	PGE	SOE	na	na	110

Notes: IPP = Independent Power Producer. PGE = Pertamina Geothermal Energy. PT = Limited Liability Company. PLN = Perusahaan Listrik Negara (National Electricity Utility). SOE = State-Owned Enterprise.
Source: GeothermEx (2010, pp. 3–9), Wells and Ahmed (2007, p. 264), Interviews.

4.3 Project implementation in the geothermal sector: Trends and issues

4.3.1 Geothermal power producers and stakeholders

The sector is dominated by two state-owned enterprises (SOEs), PERTAMINA/PGE and Geodipa, one large international corporation, Chevron, and two smaller IPPs which are joint ventures, Star Energy and Medco (see Table 4.2).[45] Attracting private sector development in the geothermal sector has been not very successful since the Asian Financial Crisis of 1998.

Interviews were conducted with representatives from three geothermal power producers and various stakeholders between 2011–2012. These interviews capture the perceptions and views on MR No. 32/2009 and the discussions leading up to the revised FIT regime under MR No. 22/2012 (see Appendix 4.1 for list of interviews). In the following sections, the main insights and emerging policy issues are presented.

4.3.2 Insufficient tariff levels as a legacy of the Asian Financial Crisis

In general, geothermal developers faced project implementation problems due to uncertainties arising from negotiations with PLN to settle a final PPA tariff rate. One common feature is that they have had to accept PLN's lower tariff for the electricity generated from the older legacy GWAs (Interview 18).[46] All three developers say that the final PPA price is economically not viable. They can afford it because they took over existing infrastructure for which they did not have to provide new investment expenditures or rely on CDM finance to support the agreed tariff with PLN (Interviews 15, 16, 17).

[45] In 2002, PERTAMINA and PLN established a joint subsidiary, PT Geodipa Energi which took over the Dieng and Patuha fields in 2002. PT Geodipa was given the mandate to explore and develop geothermal fields and build and operate power plants. Moreover, PT PERTAMINA Geothermal Energy (PGE) was established via MR No. 23/2003 as a geothermal subsidiary. PGE was given preferential development rights to very prospective fields, and still assumes the role of a contract administrator for the existing JOC operations under the old GWAs. Finally, in 2008 PLN established another subsidiary, PT PLN Geothermal, which focused on geothermal downstream activities (Ginting et al. 2010, p. 3).

[46] From a PLN perspective, there is also some scepticism as to whether the geothermal production costs between the older PPAs from the 1990s and the current ones are really that different. Interview with Djoko Prasetyo, Head of System Planning, PLN: 'IPPs were happy to accept prices of around 5–6 cents/kWh in 1990–2000, when we talk in levelised terms. It seems hard to believe that the escalation of variable costs, which are the driver of the increased price, have been that large as to justify the prices current developers ask, which are 9 cents/kWh above.'

PLN's reluctance to commit to geothermal FITs is to a large extent a legacy of the 1998 Asian Financial Crisis. In the 1990s, under the old legacy GWAs, the political nature of many IPP deals resulted in unfavourable terms for PLN. Many IPP projects were financed by short-term debt denominated in USD, but revenues were in Indonesian Rupiah. IPPs were thus exposed to exchange rate risks that were passed on to PLN in the PPAs. In the aftermath of the crisis, the utility had to restructure debt and renegotiate deals with international arbitrators (Wells & Ahmed 2007).

From Table 4.2 on geothermal fields and development status, we can see that almost all the original PPA tariffs of the first IPP projects in the 1990s had to be renegotiated to make the project viable and acceptable to PLN. Moreover, all the renegotiated prices ended up being lower than the original PPA tariffs. These renegotiations lasted well into the second half of the 2000s, even after the enactment of the new geothermal framework in 2003.

4.3.3 Problems with feed-in tariff Ministerial Regulation No. 32/2009

Against this background, the MEMR introduced MR No. 32/2009, which set a FIT of 9.7 cents/kWh as a ceiling price. This means that PLN would automatically accept any bids below that price from the winning tender. If a geothermal producer won the tender with a bid above 9.7 cents/kWh, it had to enter negotiations with PLN to agree on a final PPA price.

The main uncertainty stems from the unclear relationship between the geothermal FIT price and the tender mechanism, which still leaves space for negotiations. To some extent, PLN seems to be relatively comfortable with the negotiation space afforded by the relationship between the bid price of the tender process and the mandated FIT under MEMR MR No. 32/2009. Officially, PLN can only take the maximum price under the FIT regulation, but informal negotiations with developers are common and PLN shows some flexibility on a case-by-case basis, especially in regional grids where the supply cost is very high. Thus, prices can be negotiated up or down. How these price negotiations go depends on the nature of the IPPs and PLN's own estimates of the costs of supplying regional electricity. However, the 2009 FIT regulation at least serves as a benchmark. Before the 2009 FIT regulation, PLN was not really required to take up RE at a certain price (Interview 15).[47]

To illustrate the gap between price expectations of PLN and the IPP, consider the case of Star Energy. The firm's development of the Jailolo field in North Maluku has been hampered by different views on the level of purchasing tariffs. Star Energy won the bid to develop the field in the tender process in 2009. However, the bid price was very high at around 1727.54 IDR/kWh or 17–19 cents/kWh. Officially, PLN clearly thought that it was too high.[48] The company argued that they submitted the bid price before the geothermal regulation of 2009 came into effect, so they have every right to negotiate a higher tariff as the bid was accepted (Interview 15).

Ensuing negotiations in 2011 revealed a more ambiguous stance of PLN on the tariff rate. Informally, PLN signalled that the higher price would be acceptable, if PT Star Energy could consider building a larger generation capacity of 20 MW, instead of the planned (and bid) 10 MW. From the utility's perspective, a larger generation capacity than planned would leave some room for reserve supply if needed and would also result in a cheaper cost per MW. The cost of supplying electricity in North Maluku is considered to be extremely high at an estimated 20–30 cents/kWh, based on PLN's internal regional production cost. Thus, even if PLN would pay 15 cents for geothermal electricity, it should still be cheaper for them than solely relying on diesel-powered generation (Interview 15).[49] The IPP's response was that they would be willing to go along with this proposal as long as PLN guarantees to buy all of the electricity.

The firm also argued that in contrast to traditional contracts for coal and gas projects, the geothermal contract with PLN for their projects in Wayang Windu did not use tariff calculation formulas with specific cost items (e.g., capital, fixed operations and maintenance (OM), variable OM and fuel costs). During negotiations in 2005–2006, Star Energy argued for a more comprehensive and complex formula to account for high

[47] Interview with Alex Smillie, PT Star Energy. 'PLN is actually a very reliable customer. Bills are paid reliably, once they have signed the PPA. The problem with PLN is not reliability as a buyer, it is to get them to sign a PPA at a price they really like.'
[48] See for instance, 'PLN dan Star Energy Negosiasikan Harga Listrik Panas Bumi Jailolo', *Finance Today*, 14 March 2012, http://www.indonesiafinancetoday.com/read/23766/PLN-dan-Star-Energy-Negosiasikan-Harga-Listrik-Panas-Bumi-Jailolo.
[49] Interview with Alex Smillie, Senior Manager, PT Star Energy. Moreover, the quality of electricity supply is very poor. For instance, during a recent field visit at Jailolo, all five existing power generators were all broken down and there was no electricity. The local PLN manager had to go to Ternate to get spare parts.

capital costs, but PLN insisted on a simple contract structure with a single price (Interview 15).

Additionally, there is uncertainty associated with the geothermal framework, especially with the institutional process and the capacity to manage the tender. The IUP and the tender process are handled by the regional/local governments, which have limited human resource capacities (Resosudarmo & Burke 2012, p. 313). However, the PPA and the negotiations on the final selling price of geothermal electricity are processed centrally by PLN. Thus, IPPs face two different government players and uncertainties about the relationship between the bid prices of the tender and the negotiations in the PPA (Castlerock 2011; Interview 16).[50] Moreover, PLN has inadequate human resources to conduct PPA negotiations with many project developers at the same time. This leads to delays. Finally, the current system of negotiating tariffs on a plant-by-plant basis is lengthy, taking up to two to three years per plant (Castlerock 2010).

Another geothermal IPP, Chevron, indicated that its economies of scale and experience of being active in Indonesia since the 1980s have helped in negotiating with PLN (Interview 2). Even with the mandated 9.7 cents/kWh under MR No. 32/2009, there is room in PPA negotiations to bargain over the scale of the capacity expansion to arrive at a satisfactory price (Interview 2).[51] During the period of the project implementation in the Darajat site (2004–2007), about 80% of Chevron's annual capital budget was invested in oil and gas projects (Interview 16). This points to some internal capacity to cross-subsidise geothermal operations during periods of high oil prices.

However, Chevron had to settle with an unattractive tariff rate for its third unit at the Darajat site (Interview 16). While project documents and the interview with the representative of Chevron did not reveal the agreed PPA price with PLN at Darajat Unit 3, it is clear that the project depends on the CDM mechanism to make it operational. According to the UNFCCC (2010a) Project Design Document for the Darajat III project, the prevailing selling price for electricity with a single sole customer does not make this

[50] Interview with Alimin Ginting, CEO Chevron and Indonesian Geothermal Association. For one, the tender outcome can be challenged by other bidders.

[51] Interview with Alimin Ginting, Chevron. 'For instance, if the company says we plan to develop 220 MW of geothermal capacity at 9.7 cents/kWh, but PLN won't accept because it has not the capacity for transmission to accommodate that much power in the region, then we can agree with them to develop 110 MW first and the remainder at a later stage. This sort of negotiations can always happen.'

a particularly attractive investment option. Further, the CDM is cited as a critical aspect by senior Chevron executives, because it gives the project strategic fit within Chevron's global operations (UNFCCC 2010a, p. 17).

The case of another firm, Geodipa Energy, shows that even in the case of government-owned geothermal projects, financing problems and negotiating the appropriate tariffs with PLN were important stumbling blocks in getting the projects off the ground (Interview 17). The development of a new field in Patuha was marked by differing views on the PPA price. PLN will buy the electricity produced by the plant at 6.8 cents/kWh. However, the tariff is still not sufficient for Geodipa, and the company estimated the feasible tariff at around 12 cents/kWh. But as a fully government-owned SOE, it expects to receive subsidies under the PSO framework, making the investment feasible. Moreover, as a SOE, it also has greater access to international donor financing such as from JICA (Interview 17).

Fundamentally, there seems to be various interpretations of whether MEMR MR No. 32/2009 constitutes a FIT in the sense that PLN is fully obliged to take up the electricity. The regulation itself is mostly understood as a ceiling price by PLN representatives, at least in the geothermal sector. It is conceived as a regulation 'moving in the direction of a feed-in tariff' (Interview 20). However, in many cases, the prevailing price cap mandating 9.7 cents/kWh under MEMR MR No. 32/2009 can exclude some economically justified development, especially in areas where diesel-fired power generation is much costlier (Interview 21).[52]

Generally, connecting rural off-grid areas is financially not attractive to PLN, as these are mostly sparsely populated, have very low load factor and the customer base falls largely into the lower-income bracket that uses subsidised diesel generators. The lack of transmission capacities means that many RE plants need to connect with the load centre, which adds to costs. Although PLN has an incentive to reduce the use of subsidised diesel, renewables or clean coal technology-based options are still not the

[52] Interview with Mike Crossetti, Castlerock Consulting: 'The 9.7 cents/kWh under the 2009 regulation excludes the places where you most wanted to do geothermal, like in Nusa Tenggara Timur, where those plants run at 10–15 cents but are economically better options than diesel plants. In theory, it doesn't prevent business-to-business negotiations if you agree that the price has to be higher, but it would have to go through a more rigorous review process by the Ministry.'

automatic choice for PLN, as conventional coal is still the cheapest alternative (USAID 2009, pp. 11–13).

All three developers insisted on higher tariffs for their newly planned operations, usually exceeding the mandated ceiling tariff of 9.7 cents/kWh under MR No. 32/2009 (Interviews 15, 16, 17).

In the case of Geodipa, their main incentive to become a full SOE was that they could benefit from the PSO subsidy. This, in turn, will enable them to afford the lower tariff proposed by PLN for their newly planned operations and gain access to international donor finance.

From the perspective of an IPP, the role of PLN as an investor is limited by its financial constraints and its need for the electricity subsidy. The PSO subsidy increases the pressure for the utility to minimise its costs in all aspects of the electricity business, impacting its decision to purchase electricity from IPPs. In fact, from an IPP perspective, PLN should merely act as a buyer of energy, and not invest in running its own plants, especially in the geothermal sector with its high initial exploration and fixed costs (Interview 15). Presumably, this would free up more resources for PLN to buy energy from renewable IPPs, even if the mandated FITs are set above PLN's average production costs.

A general structural constraint is that the domestic financial sector is too small to fully fund the geothermal program under FTP 2. The geothermal capacity of the FTP 2 is around 4,000 MW. Assuming it will cost about US$3 million/MW to set up a geothermal plant, this would already amount to US$12 billion. International financing is needed in any case. In the case of Star Energy, Standard Chartered Bank provides a syndicated loan with three Indonesian banks to the Wayang Windu operations. As the company wanted to have an international EPC contractor to build the plant, the risk is passed on to the contractor. The EPC contractor wants a guarantee to access the money, and so demanded a bank with high (AA) credit rating, which automatically ruled out many of the Indonesian banks (Interview 15).

Statistics from PLN in 2011 confirm that pricing issues played a significant role in slowing down project implementation. Six of the 11 projects under the geothermal component of FTP 2 stated that the price was a problem (see Table 4.3). In three cases, bid prices were lower, but the developers argue that the price is not adequate and have asked for renegotiated prices (Interview 22). Bids which won the tender with a higher price have also entered renegotiations, as PLN insisted to adhere to the capped price under MEMR MR No. 32/2009 (Interview 19).

Table 4.3: Price issues in geothermal IPP projects in 2011

Geothermal IPP	MW	Cents/kWh	Status
Muara Labuh/PT Supreme Energy	220	9.4	Price accepted by MEMR
Rajabasa PT Supreme Energy	220	9.5	Price accepted by MEMR
Atadei/PT Westindo	5	9.5	Price renegotiated to 9 cents
Sokoria/PT Sokoria	5	12.5	ESC agreed except price
T. Perahu/PT T. Peerahu	110	5.8	Developer objects to tender price
Tamomas/Pt Wijaya Karya	45	6.5	Developer objects to tender price
C.Cisukarame/PT Jaba Rekind	50	6.8	Developer objects to tender price

Notes: IPP = Independent Power Producers.
Source: PLN (2011b).

4.3.4 Problems with non-geothermal regulations

Policymakers have had to address several regulatory conflicts arising from the geothermal framework under Law No. 27/2003, which fostered investment uncertainties and necessitated time-consuming processes to harmonise different views and regulations (Ginting et al. 2010, p. 5; Interview 16). Although the geothermal framework under Geothermal Law No. 27/2003 grandfathers all terms and conditions of existing geothermal operations in the old GWAs, developers faced disputes with local governments on tax issues. It took the central government several years to reach an understanding with regional governments on the proper allocation of tax revenues (Ginting et al. 2010, pp. 3–4).[53]

Moreover, the fiscal decentralisation process also blurred the lines of authority between central and regional governments in regard to issuance of geothermal mining licenses (Izin Usaha Pertambanganan Panas Bumi (IUP)). Local governments claimed the rights for IUP issuance for themselves in the wake of fiscal decentralisation. However, Geothermal Law No. 27/2003 and GR No. 59/2007 state that both central and local governments have the right to issues the IUPs. The current interpretation by policymakers is that the regional government processes the IUP but with significant input from the MEMR in Jakarta (PWC 2011, p. 49).

One peculiarity of the regulatory framework is that the core of geothermal activities, the production of steam, is regulated under the 2003 Geothermal Law, but power generation is covered under the 2009 Electricity Law (Interview 1). This means there are two different regulatory regimes dealing with electricity generation from geothermal plants. This adds to administrative hurdles in processing the necessary documents for geothermal developers. Thus, project developers need to obtain an IUP and an IUKU to operate a fully integrated operation. Under the previous regulations, licences were integrated under the Joint Operation Contract arrangement (PWC 2011, p. 23).

The negative investment list provides another impediment to increased foreign investment flows into the geothermal sector. As stipulated in Presidential Regulations (PRs) No. 77/2007, 11/2007 and 36/2010, certain business activities in several sectors are either closed or impose limits to foreign investors. For example, all projects below a generation capacity of 10 MW are open to Indonesian developers only. Moreover, these projects need to be implemented in partnership with small/medium business and cooperatives, but the requirements for this cooperation are not clearly spelled out in the regulations. Lastly, support services in the geothermal sector such as OM and drilling allow only 90–95 per cent foreign ownership in equity shares (Norton Rose 2012).

---

[53] Amendment to Decentralization Laws No.22 and 25/1999): Law on Regional Autonomy No.32/2004 and Law on Regional Finance No.33/2004

Geothermal project developers also face laws to regulate forest land and protect conservation forests. Forest Law No. 41/1999[54] prevents specific economic activities to take place in the absence of government permits. This has caused uncertainties in the geothermal investment community, as many promising geothermal fields are located in protected forests. Only in February 2010, a Presidential Decree (PD) allowed for 'strategic' activities, including power plants, in protected forests.

The DG of Forest Protection and Nature Conservation under the MoEF has announced that geothermal projects do not need to obtain permits anymore to operate in protected forests, but they need to enter into profit-sharing arrangements with conservation funds to be paid to the MoEF (PWC 2011, p. 26). Energy projects of national significance are also exempted from a 2011 moratorium on permits for forest and peat land clearing. Geothermal Law No. 21/2014, finally allowed for geothermal activities to be conducted in production, protected and conservation forests.

Chevron, for instance, faced conflicting regulations that directly impacted its operations in both Darajat and Salak fields. The forest land status of the Salak geothermal field had been a conflict that had to be resolved with the MoEF. In 2003, the MoEF issued Decree No. 126 to change the status of the land from a 'protected forest' to a 'national park'. Geothermal activities under the Forestry Law No. 41/1999 were prohibited. There were long negotiations with the MoEF until the conflict was resolved when the Ministry issued a letter and regulations that accommodated continued geothermal activities within national parks, because the approval of the geothermal field pre-dated the Forestry Law (Ginting et al. 2010; Interview 16).

Finally, land acquisition laws provide another set of hurdles for developers to clear before starting operation of power plants. For a long time, the prevalent regulatory instruments contained significant limitations to the extent investors could appropriate land (PWC 2011, p. 26).[55] It was not until December 2011 that Parliament (DPR) approved a new Land Acquisition Law, designed by the National Land Agency. It imposes clear time limits on the land acquisition process and provides more investment

[54] Together with amendments of 1/2004 and 19/2004.
[55] PDs 36/2005 and 65/2006 and No. 3/2007on land acquisition for public purposes.

certainty, but this depends, again, on the timely and transparent implementation of GRs.[56]

An example is Star Energy's Wayang Windu operations, for which PLN originally agreed to build two transmission lines for Unit 2. This was supposed to be completed in 2008, but as of 2011, PT Star Energy was still waiting for the line to be completed. The main reason is that the owners of two small parcels of land put up resistance. In many countries there are land laws, based on the principle of *eminent domain*, which state that the government will pay a fair price and compensate for land that is compulsorily acquired. This does not exist in Indonesia and people can hold on to their land. The new land law should improve the situation (Interview 15).

4.3.5 Revised geothermal feed-in tariff regulations 2012–2015

The shortcomings of Geothermal Law No. 27/2003 and the FIT under MR No. 32/2009 led to broad-based stakeholder discussions aiming to reform the geothermal framework. The ceiling FIT under MR No. 32/2009 was not deemed effective in attracting investment, as no PPAs above 9.7 cents/kWh seemed to have been completed (World Bank 2015, p. 13). As stakeholders concluded, the rationale underlying the ceiling tariff was not clear, except for minimising PLN's cost (World Bank 2015, p. 13). They are not deemed effective, if they are negotiable for individual developers after a tender and if they are not revised regularly due to changes in exploration costs or general inflation (World Bank 2015, p. 14).

In 2010–2011, the MEMR commissioned the Castlerock consultancy firm to come up with recommendations to improve the existing geothermal policy framework. The study assessed and compared the production costs between geothermal power and coal-fired generation. Based on an assessment of the geothermal resources of 50 WKPs, the LCOE for each geothermal WKP were determined on a probabilistic basis to capture uncertainty and risk. The study also assessed the LCOE for coal-fired generation on each grid where geothermal development is expected (Castlerock 2011, p. 20).

---

[56] 'Still long way for implementation of Land Acquisition Law', *Jakarta Post*, 13 February 2012. In August 2012, the president signed an implementing regulation for Law No. 2/2012 on Land Acquisition for Public Facilities that sets an unambitious maximum time of 583 days for the land acquisition process for new public projects (*Jakarta Post*, 16 August 2012). It is too early to determine whether the new regulation will have any effect in getting infrastructure projects moving.

The authors presented several findings in regard to pricing policies. First, the geothermal prospects that were assessed are generally competitive with coal-fired generation when environmental externalities are included. Second, however, geothermal power is expected to be costlier than coal-fired generation if no externalities are included. This price gap constitutes the 'incremental cost gap'. Third, the range (standard deviation) of potential production costs from any given geothermal field is much greater than for coal-fired generation, reflecting the uncertainty in the underlying geothermal resource base.[57] The geothermal incremental cost gap is estimated to be US$95 million in 2014 and US$187 million in 2016, under a business-as-usual (BAU) scenario with and no value for externalities. The authors suggested that an increased PLN subsidy or tariffs were the most viable options to fund this incremental cost gap (Castlerock 2011).

The study proved influential in guiding stakeholder discussions to reform the geothermal sector. In 2012, a US$300 million Geothermal Fund was established under the MoF to reduce initial exploration risks of private developers (MoF Regulation No. 3/2012). The fund aimed to fund exploratory drilling activities of private developers, thus reducing initial exploration risks and providing more reliable data for bidders. However, the MoF and its fund manager, the Indonesia Investment Agency, have not finalised the operational details of the Geothermal Fund and its resources remained undisbursed by the end of December 2015 (Asian Development Bank & World Bank 2015, p. 28).

Based on the findings of the study, MEMR also issued new FITs under MR No. 22/2012 on the Obligatory Purchasing Price of Geothermal Electricity. The regulation issued fixed tariffs but differentiated based on geographical location and voltage class (see Table 4.2). However, no PPAs under No. MR 22/2012 were completed (World Bank 2015, p. 1). Ensuing stakeholder discussions concluded that the 2012 FIT regulation was not effective in attracting investment, because the fixed tariff system meant that tender bids would be decided based merely on non-price issues. Many developers regard this as

[57] Specifically, the calculated mean geothermal LCOE is 12 cents/kWh. Given the standard deviation of 2.3 cents/kWh, the LCOE results within one standard deviation range from 9.7 cents/kWh to 14.3 cents/kWh so that there is a roughly 68% chance that the LCOE will fall within this range. The calculated range for coal-based LCOEs fall between 6 and 14 cents/kWh, reflecting differences in location and size of the plants (Castlerock 2011, p. F-15).

unfair, as it leaves the evaluation process open to subjective criteria (World Bank 2015, p. 1).

Further consultations—led by the ADB and World Bank and aimed at promoting dialogue between MoF and MEMR—resulted in another revision of the FIT regime and an overhaul of the Geothermal Law. In 2014, MEMR MR No. 17/2014 was issued. They constitute the most comprehensive and differentiated FIT regime to date, with prices based on location-specific criteria and project COD (see Table 4.1).

Conceptually, the 2014 tariffs are tender-determined ceiling prices, similar to the MR No. 32/2009 regulation. Competitively bid ceiling tariffs are based on the economic benefits of geothermal energy. These benefits are calculated based on avoided costs (e.g., avoided external costs of thermal generation). Moreover, these tariffs are set as a process, targeting CODs and reflecting future price developments. It can be argued that these do not represent FITs, which are usually based on production costs of the employed technology (Asian Development Bank and World Bank 2015, p. 148).

4.4 Discussion: Key issues and policy implications of the Indonesian feed-in tariff regime

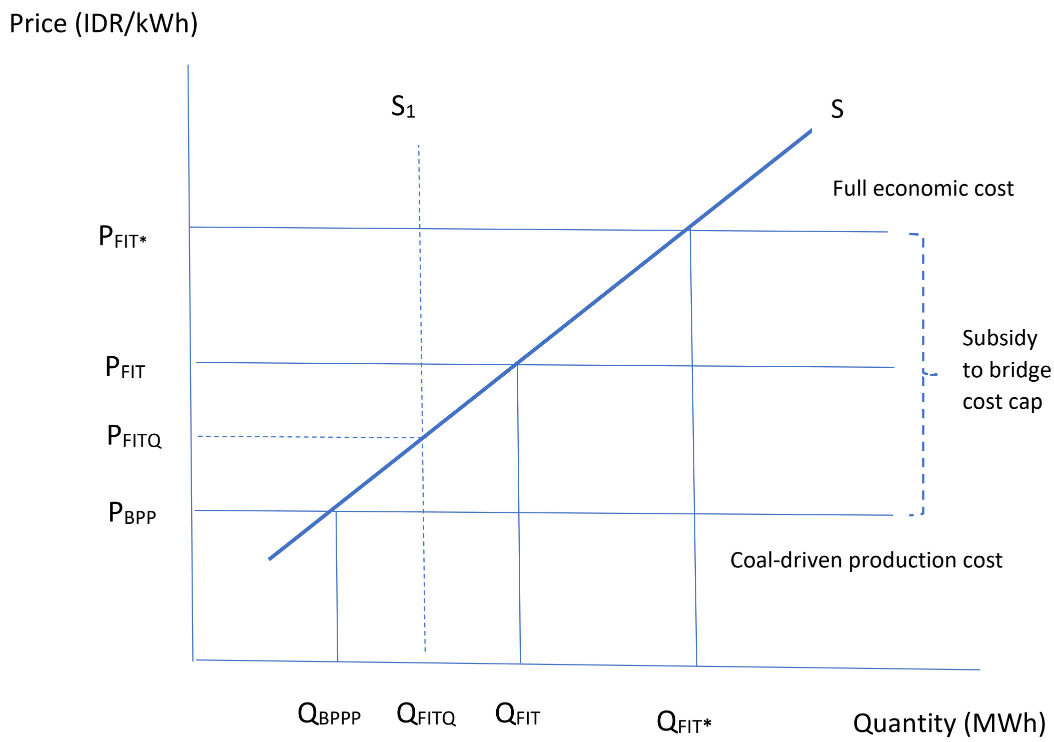
Overall, the findings confirm well-known challenges in the geothermal sectors (Siwage 2014). Investors face high exploration risks which are exacerbated by the absence of government guarantees to cover those risks. In addition, geothermal resources are frequently located in remote areas which makes connection to PLN grids costly. There is also a lack of human resources and capacity in preparing documents in a complex tender process. Lack of local capacity in project maintenance is a prominent factor. Moreover, there are problems in interpreting the regulations. Finally, the price of electricity is not economically feasible for IPPs to sell to PLN (Siwage2014).

The analysis in this and the preceding chapter have made it clear that the FIT regulations in Indonesia have not been effective. The main underlying factor is that PLN simply prefers to buy coal- or gas-fired generation which are cheaper than renewables. The utility does take coal- and gas-fired generation costs as benchmarks to set average BPP in all grids in Indonesia. In most off-grid areas, PLN relies on diesel-based generators to connect rural communities. Despite diesel being more expensive than renewables, it has been subsidised for much of the period under investigation (1990–2015) so that PLN has only reluctantly taken up renewables in off-grid areas. It should also be noted that the potential for solar and wind varies across the archipelago. The costs of supplying integrated maintenance and supply systems might be a significant factor that prevents the utility to switch to renewables in remote islands.

Essentially, the design of past and current FIT regulations could not resolve the following dilemma: on the one hand, the Indonesian FIT does not act as a premium price sufficiently attractive to many IPPs, while on the other hand, PLN is in many cases not willing to buy renewables at the mandated tariff rates because it has cheaper options available. Thus, the FIT is a purely price-based instrument without a legally binding obligation for the utility to meet a quantitative RE target.

Figure 4.2 provides an intuitive economic analysis to illustrate the effects of the FIT in the Indonesian RE market, including both SMPPs and geothermal power. The RE supply curve (S curve) represents the quantity of RE IPPs are willing to supply to the grid, with increasing prices incentivising more players to enter the market. Changes in the cost structure of renewable technologies could push the supply curve up and to the left, reducing the quantity at a higher cost. Conversely, lower costs would push the curve down and to the right, increasing the supply of renewables. An example for the former case would be geothermal technology which has high fixed costs and faces many regulatory uncertainties. Solar power technologies are an example of the latter case, as global costs have come down considerably, but this has not yet translated into lower costs in Indonesia due to regulatory uncertainties associated with the FITs.

Figure 4.2: Feed-in tariffs and supply of renewable energy



Currently, PLN is only willing to buy renewables at price P_{BPP}, a level that presents the utility's average BPP, resulting in a quantity of RE Q_{BPP}. Note that this represents the maximum amount of RE PLN is willing to buy: as discussed in the previous chapter, FIT regulations have for a long time not mandated specific tariff levels but set purchasing prices as a percentage of PLN's production costs.

Since 2009, FITs for both geothermal and SMPPs were set at fixed prices for PLN to buy renewables. These tariffs were set above PLN's average production costs, which are largely driven by coal and natural gas-based generation costs. P_{FIT} and Q_{FIT} would represent the optimal quantity of renewables that would be achieved in the market if the utility would buy at the mandated FIT levels. The empirical and historical analysis provided so far suggests the utility is only willing to buy or invest in renewables at an amount somewhere between Q_{BPP} and Q_{FIT} and treating the mandated FIT at P_{FIT} as a ceiling price, with room to push for an even lower price when negotiating PPAs with IPPs.

If the FIT would be designed as a true premium price, at P_{FIT*}, then Q_{FIT*} denotes the quantity of renewables that would be delivered by IPPs in the market. Arguably, this premium price could be set at a level that represents the 'true' economic cost of fossil fuel–based power generation, which includes the significant cost of fossil fuel subsidies (see Chapter 5) and the environmental damage costs of coal-based power generation. Thus, the difference between P_{BPP} and P_{FIT*} would constitute an 'incremental cost gap' (Castlerock 2011) or the subsidy needed to bridge the cost between PLN's supply cost and the premium FIT.

The shortcomings of the Indonesian FITs confirm some of the main disadvantages associated with this instrument, which are documented in the literature. First, the size of the incremental cost of supporting FIT schemes can be a significant barrier to effective design. Huenteler (2014) found in the case of Thailand that these incremental costs can be quite substantial, estimated at around US$21 billion or 3.2 per cent of GDP in 2012. Looking at the case study of setting up a global FIT fund in Tanzania, Rickerson et al. (2013) found that mitigation of project development and financial risks would be the primary objectives to enable a FIT scheme. In short, setting up FIT schemes requires substantial funding from government, private sector and international donors.

Second, incremental costs to support FIT regimes do exhibit significant uncertainty, as they are largely driven by the savings obtained from avoiding costs of fossil fuel consumption. However, coming up with estimates of counterfactuals (e.g., built power plants and fuel types consumed in the absence of renewable power generation) that are acceptable to the domestic government requires a long process of policy learning and experimentation. Moreover, this uncertainty affects the design of a FIT schemes, as donors might be unwilling to commit to backing FIT schemes, if they do not know the required size of the financial flows. Investors might also hesitate if no guaranteed long-term support commitment in place (Huenteler 2014, p. 870).

Given the ineffective use of FITs, should other policy instruments be considered? A body of literature suggests that an effective promotion of RE is not a matter for prioritising one instrument over others, but that the right mix of policy instruments matters. Davies (2012) makes the case for combining RPSs with FITs. In many ways, both instruments complement each other, thereby allowing policymakers to reap the benefits of regulatory synergies (Davies 2012, p. 313). PRSs focus on quantity-based targets and thus provide accountability in both policy and regulatory terms. FITs, as discussed earlier, are price-based instruments and could complement RPSs with market certainty by setting an upfront cost of compliance and guaranteeing the purchase of renewables-based electricity (Davies 2012, p. 313).

Quota obligations for utilities have been used in various countries and are known as RPSs in the US, RESs in India, Renewables Obligations in the United Kingdom, and Renewable Energy Targets (RETs) in Australia (IPCC 2011, p. 895). Under these quota systems the utility is obliged to take up renewables into the grid and any additional costs can be passed on to the consumer.

Several studies suggest that RPS work well in combination with other policies and in long-term settings. Carley (2011) undertook a comparative scenario analysis of state-based policies in the US and found evidence that RPSs in combination with another instrument—a carbon price—is more effective in reducing emissions than when applied alone. Fischer (2009) argues that RPS are essentially a combination of both a subsidy (given to RE producers) and a tax (imposed on producers on fossil fuel–based energy suppliers). The impact of RPS on electricity prices depend on the size of the tax and subsidy effects, which in turn depend on the elasticity of supply curves in renewable and non-RE markets. Most studies suggest that if there are rigidities in natural gas supplies, then RPSs will lower consumer prices. This might be relevant for the Indonesian context where much of the generated electricity is highly dependent on domestic natural gas production. Finally, evidence from US-based literature suggests that RPSs are particularly effective in creating green investment and business, if they are allowed to persist in force for a number of years (Bowen, Park & Elvery 2013).

So how could PLN be incentivised to take up more renewables in the future? Clearly, as a purely price-based mechanism, past and current versions of Indonesian FITs did not work because PLN was not obliged to take up a legally binding quantitative target of renewables. In Indonesia, future policies could strengthen the effectiveness of FITs with RPSs for the utility. Looking at Figure 4.2, such a quantitative target could be curve S_1 which lies between PLN's preferred price at P_{BPP} and P_{FIT}, resulting in a price level at P_{FITQ}. It would still not be a tariff which reflects the full economic cost of renewables, but recent reforms have made electricity tariffs more cost reflective and made the utility less dependent on the PSO subsidy (see Chapter 5). In future, these tariff reforms should put PLN in a better position to take up renewables at prices closer to the premium level, especially with costs of solar and wind power falling.

4.5 Conclusion and outlook

This chapter has provided an analysis of the geothermal policy framework, focusing on three aspects. First, it gave an historical analysis of the policy and regulatory framework governing the geothermal sector since the 1990s, finding that FITs have only really played a role since 2009 as part of a broader, complex regulatory and investment climate context. Despite being the only RE sector governed by laws, Geothermal Laws No. 27/2003 and then No. 21/2014, implementing regulations were not consistent, thereby increasing investment uncertainty in the sector. Regulatory barriers included overlapping administrative processes with regard to processing forestry licenses, land permits and environmental impact assessments. These were aggravated by the unclear allocation of responsibilities between central and regional government in processing geothermal licenses.

Second, based on interviews with geothermal IPPs and policymakers, the chapter presented the key issues and challenges associated with the implementation of the geothermal FIT regulations, focusing on the period 2009–2015. Like in the case of SMPPs, the design of the geothermal FIT instrument is deemed ineffective by most stakeholders due to a mix of inadequate tariff levels and wider regulatory and investment climate risks. Moreover, geothermal FIT regulations are tied to a competitive tender mechanism for project developers. Much of the uncertainty stems from the unclear relationship between the geothermal FIT price and the tender mechanism, which resulted in lengthy negotiations between PLN and geothermal producers.

Third, the chapter presented an intuitive economic analysis to capture the effects of the Indonesian FIT regime—both for the geothermal IPPs and SMPPs—on the supply of RE in the Indonesian electricity sector. Specifically, it addresses the core dilemma of the Indonesian FIT regulations for both geothermal IPPs and SMPPs: mandated tariff levels are not set at a premium rate high enough to attract most IPPs, while at the same time PLN perceives the prevailing FITs as too costly relative to cheaper coal-based generation options.

Increasing the effectiveness of future FIT regimes depends to a large extent on the financial conditions of PLN and the price competitiveness of renewables vis-à-vis coal and gas. Policymakers have recognised that the design of an effective FIT regime must acknowledge this 'incremental cost gap' between renewables and thermal generation. In the geothermal sector, reforms since 2014 have moved the FIT regime from a purely production cost-based FIT to competitive tender-determined ceiling tariffs based on avoided costs. However, if increasing renewables is a serious goal for policymakers, then a price-based instrument like a FIT must set a sufficiently high premium price or a mandatory quantitative RE target should be set for the utility.

Overall, the Indonesian experience with implementing FIT regulations suggests that their shortcomings confirm some of the main disadvantages associated with this instrument which are in line with similar studies in the literature. These problems mainly relate to uncertainties regarding the size and the stream of the incremental cost of supporting FIT and determining the appropriate level of tariffs to attract IPPs, especially within a policy context of a state utility exercising its leverage as a single buyer on the grid.

A body of literature on energy policy instruments suggests that the Indonesian context warrants the application of a right mix of instruments rather than prioritising one instrument (e.g., FITs) over others. Future policies could strengthen the effectiveness of FITs with RPSs for the utility. This would combine the incentives of a price-based instrument with the policy accountability associated with a quantity-based RPS.

Appendix 4.1: List of interviews

Interview 1	Joko Winarno, Renewable Energy Society Indonesia; Masyarakat Energi Terbarukan Indonesia (METI)
Interview 2	Erwin Sadersa, METI
Interview 3	Hadi Susilo, Renewable Energy Division, PLN
Interview 4	Abianto, Project developer for PT SKM and BSP
Interview 5	Fenny Rahayu and Andri Suhindra, Staff Renewable Energy Division, Ministry of Energy and Mineral Resources (MEMR)
Interview 6	Tri Mumpuni and Iskandar, IBEKA
Interview 7	Fabby Tumewa, Director, Institute for Essential Services Reform
Interview 8	Jamsa Suwardi, Director, PT SKE
Interview 9	Robert Batara, PT Fajar Futura
Interview 10	Mohamad Assegaf, PT Bumi Investco Energi
Interview 11	Tiopan Marpaung, President Director, PT Inpola Meka Elektroindo (IME)
Interview 12	Bagus Mudiantoro, Project Implementation Officer, ADB
Interview 13	Agus Nugroho Santoso, President Director, PT Navigat Organic
Interview 14	Santoso, Association of Indpendent Power Producers
Interview 15	Alex Smillie, Senior Manager, STAR Energy
Interview 16	Alimin Gnting, Chevron and Indonesian Geothermal Association
Interview 17	Kurnia Rumdhony, Business Development Manager, PT Geodipa
Interview 18	Djoko Prasetyo, Head of System Planning, PLN
Interview 19	Anang Yahmadi, Head of Geothermal Division, PLN
Interview 20	Mohamad Sofyan, Head of Renewable Energy Section, PLN
Interview 21	Mike Crossetti, Castlerock Consulting
Interview 22	Rahman Mohamad, IPP Division, PLN

Chapter 5: The Implications of the PLN Subsidy Regime for Renewable Energy

Abstract

This chapter analyses PLN's financial governance system, the historical trends of its subsidy and revenue streams, and the implications for RE investment. The main findings of the chapter are as follows. First, the utility's budget is subject to a political process, which does not prioritise investment into RE. Second, given that the subsidy is a significant part of PLN's revenues and that it is the single buyer of IPP-generated power on the national grids, uncertainty about the utility's supply costs and the size of the subsidy raise doubts among investors about the utility's general commitment to take up more renewables. Third, despite receiving subsidies and a PSO margin, PLN faces a funding gap that constrains its ability to meet expansion targets.

As a result, the utility prioritises investment in coal and gas-powered generation, which have been cheaper than renewables in 1990–2015, the main period of investigation in this thesis. Given the ineffectiveness of the prevailing FIT regulations, funding and subsidy mechanisms alone are not effective to change the behaviour of PLN. Mandatory quantitative RETs might be better suited to incentivise PLN to take up larger amounts of renewables. Despite the decline in the cost of renewables, their high upfront costs still require the application of regulatory instruments to incentivise PLN investment.

5.1 Introduction

The previous chapter showed that RE has only played a small part in the overall electricity supply mix in Indonesia, despite efforts to implement policies and programs to promote RE. This chapter looks at the institutional constraints in the electricity sector which prevent larger investment into RE. It specifically argues that a key constraint is the financial governance system under which the national utility operates. By financial governance, I mean the political and fiscal system which determines electricity tariff rates, which has an important effect on the financial performance of the utility.

The main characteristic of the financial governance system in Indonesia's power sector is that tariffs do not reflect the costs of supply, which makes PLN dependent on a subsidy to keep its operations going. This has been the case for much of the main observed period in 1990–2015, although regular tariff increases since 2012 have reduced the financial pressure on PLN (Burke & Kurniawati 2018). The prevailing subsidy and tariff regime has worked against renewables in the following ways.

First, the utility's budget is subject to a political process, which does not prioritise investment in RE. The size of the subsidy is decided by the government and DPR on an annual basis. Given its revenue constraints, PLN's space to invest into renewables is restricted, as it prefers to invest in cheaper coal- and gas-fired power generation. Second, given that the subsidy is a significant part of PLN's revenues and that the utility is the single buyer of power generated by the private sector on the national grid, uncertainty about 'true' supply costs and the size of the subsidy raise investment uncertainty about the utility's general commitment to take up more renewables, especially large-scale projects. Third, PLN's financial constraints have resulted in a significant funding gap, which makes aggressive electricity tariff reforms to cover PLN's costs a necessary condition to consolidate its financial base and reduce its risk aversion to take up more renewables.

Thus, the existing tariff and subsidy system does not provide much incentive for PLN to take up more renewables. Instead, the utility has favoured investment in fossil fuel–based generation technologies over renewables, especially those renewables with high upfront costs such as geothermal power. To increase PLN's willingness to invest more in renewables, implementing a cost-reflective tariff system—which has been started in 2012 and then consistently implemented by the Jokowi Government since 2014—is a necessary prerequisite to consolidate its financial base. However, given its priorities to expand and maintain the quality of the grid, it must rely mostly on private sector investment to provide clean energy.

The chapter will develop this argument in four parts. Section 5.2 provides a brief overview of the literature theorising on the link between the financial conditions of utilities and outcomes in the RE sector. Section 5.3 provides an analysis of the governance and institutional constraints in the electricity sector, focusing on the historical evolution of the tariff and subsidy system and its impact on the finances of PLN. Section 5.4 analyses three main implications for the RE sector that arise from PLN's financial governance, namely a political budget process prioritising non-renewable targets for PLN, investment uncertainties associated with the subsidy mechanism and lack of transparent electricity supply costs, and significant funding gaps for PLN to implement investment targets. Section 5.5 concludes with an outlook to various policy options to remove barriers to RE and find more effective ways to incentivise PLN.

5.2 Governance of state utilities and renewable energy outcomes: Theoretical perspectives

The role of public utilities in developing countries has mainly been scrutinised within the context of liberalisation reforms of domestic power sectors (Besant-Jones 2006; Jamasb 2006). Pricing reforms, typically focusing on the reduction of energy subsidies, are essential elements of liberalisation efforts (World Bank 2005). Policy synergies between reforms in the electricity and RE sectors in Indonesia have been less of a subject, but generally focus on the efficiency-enhancing effects of abolishing subsidies (Dubash 2002). In many emerging economies, political obstacles to liberalisation result in slow and incoherent implementation of electricity reforms, heightening uncertainty in the investment climate within which RE developers operate (Besant-Jones 2006; Jamasb 2006). Within that context, energy utilities might resist the adoption of innovative low-carbon technologies, as they have already invested in fossil fuel–based generation and are 'locked in' to certain energy systems (IPCC 2011, p. 872). Several aspects are particularly relevant for the discussion of the Indonesian case.

Governance and political economy factors in the electricity sector frequently prevent effective cost pass-through mechanisms. A study covering economies in Asia-Pacific Economic Cooperation points to the fact that the energy sectors of many developing countries are dominated by VIMs (World Bank 2011c). Typically, this means that investment carried out by utilities to expand generation capacities is centrally planned, with the VIM monopolising nearly all aspects of the power sector. Notably, the existence of policies that mandate fixed subsidy and tariff levels distort domestic energy prices (Beaton & Lontoh 2010; World Bank 2007). Distorted prices also financially constrain utilities in their ability to invest properly in expanding generation capacities, including RE technologies (World Bank 2011c).

Asymmetric information problems frequently encountered in state-dominated electricity sectors can undermine regulatory effectiveness and the long-term investment certainty needed for renewable policy instruments to work (Estache & Wren-Lewis 2009). Asymmetric information problems usually arise in situations characterised by PA features. PA theory is a useful framework to analyse conflicts of interest and coordination problems associated with delegated decision-making. In a typical PA situation, a principal authorises an agent to take decisions on their behalf. In situations where there is complete and perfect information, the interests (preferences) of the principal and agent coincide, as the former can perfectly observe the latter's choices and decisions. Hence, the principal will not have problems in making sure that the agent acts in their interest. PA theory investigates situations in which the conditions of perfect information do not apply. In PA situations, incentives and objectives differ between the principal and the agent (Gravelle & Rees 1992). Within the context of the Indonesian power sector, asymmetric information problems arise due to the lack of transparency on PLN's electricity supply costs, which serve as a benchmark for negotiating PPAs and determining the size of the subsidy to PLN.

Many RE policy instruments, notably FITs and RPSs, require long-term contracts that provide assurance of long-term price guarantees (IPCC 2011, pp. 896–900). Moreover, legislators need to be able to calculate adequate FIT levels and adjust them in a transparent manner (Mendoncana, Jacobs & Sovacol 2009, pp. 20–27). Typically, this requires a tariff setting in which an autonomous regulatory agency can independently monitor and review information on production costs and set electricity price levels (Besant-Jones 2006, p. 38). However, in many emerging economies with VIM structures, these policy and regulatory functions are not clearly divided, frequently leading to either regulatory capture or prolonged conflicts of interest between various government agencies (Laffont 2005; Estache & Wren-Lewis 2009). This can result in a lack of credible mechanisms on the government side to determine tariff levels and for state utilities to commit to long-term contracts with IPPs. Moreover, frequently electricity tariffs are mandated by the government which prevent the utility from passing on price increases directly on to consumers. Under such conditions, FITs might be less effective in increasing RE supply than anticipated (Mendoncana, Jacobs & Sovacol 2009; REN21 2011; IPCC 2011).

Public utilities in transition and developing economies frequently face a 'soft budget constraint' (SBC) environment. SBC arise when an organisation is operating inefficiently and is constantly relying on bailouts or subsidies from outside organisations to cover its deficits. In extreme cases, typical consequences of a SBC environment are rationing of power supply and frequent power outages. While SBCs are mostly associated with SOEs or government agencies, they can also be found in private and non-profit entities (Kornai, Maskin & Roland 2003).

Energy subsidy arrangements between governments and utilities are important policy factors affecting energy outcomes, including investment in renewables. Despite assurances of financial support from the government, utilities frequently face governments who are reluctant to commit the full subsidy payment, because they find themselves under budgetary pressures and public scrutiny (World Bank 2011c). Typically, governments in developing countries are reluctant to use PSO[58] payments, or other forms of explicit subsidy mechanism, because they fear that any automatic subsidy mechanism will provide incentives to the utility to be inefficient and simply pass on costs to the government (World Bank 2011). This reluctance to credibly commit resources shows that there are diverging interests and objectives between the government and the utility. Thus, utilities are being pressured to carry as much of the financial burden as possible, which affects their willingness to invest in low-carbon technologies.

5.3 Institutional constraints in the Indonesian electricity sector

5.3.1 Governance in the electricity sector: PLN's 'trilemma' of objectives

Three main features characterise the Indonesian electricity sector, each affecting RE investment. First, like in many other countries, state utility PLN acts as a VIM, dominating nearly all aspects of the national electricity supply business. Second, PLN is the single buyer of electricity in the major grids in Indonesia. Third, it is accountable to

[58] Also known in the literature as USOs (Laffont 2005).

three major ministries, and thus must balance three different sets of objectives in conducting its business.

Indonesia has adopted a VIM model, in which nearly all aspects of the domestic electricity business is owned by the government and run by a SOE. The central role of the government is rooted in the 1945 Constitution with Article 33 (Chapter XIV) handing over the mandate and power to the state to act as the sole provider of electricity.[59]

Appendix 5.1 illustrates the three-tiered governance and institutional framework in the Indonesian electricity and RE sector. The *macro* or constitutional level of governance describes actions and decisions that apply checks and balances on the government (Besant-Jones 2006, p. 38). Here, decisions about the overall policy direction in the energy sector are made because of the interaction between various players at the political and legislative level.

The president and DPR have the most powerful positions in approving laws and signing off regulatory instruments. The political parties in the DPR and especially Commission VII on energy and mining policies have important functions in reviewing and influencing draft regulations and laws about electricity policies, specifically on subsidy and tariff measures. CSOs and private firms shape public opinion and have lobbying power to influence government decisions. The judicial branch of the state has asserted a more powerful role since 1998 and has for the time being cemented the government's central role in securing electricity supply. The roles of these agents at the macro level are governed by Electricity Law No. 30/2009 and Article 33 of the 1945 Constitution.

The president has the power to use PDs to either speed up implementation of existing policies or define new priorities. While the current governance system has given more power to the legislative and judicial branches of government, it has retained a strong centralised feature by giving the president continued executive powers in the form of PDs and instructions. These can significantly influence the direction of the legislative process, especially in the short term. Moreover, these discretionary powers cause

[59] Indonesia declared independence and a constitution in 1945, but formal independence from the Dutch was achieved in 1949. In strictly legal terms, the legal framework for the electricity sector also refers to an old regulation from the colonial era, namely the 1890 Dutch Ordinance on 'Installation and Utilisation of the Conductors for Electrical Lighting and Transferring Power via Electricity in Indonesia' (PWC 2011, p. 10; PLN 2010, p. x).

general regulatory uncertainty, which reduces the attraction to invest in long-term projects.[60]

At the meso level, political decisions are translated into policy action and administrative processes. We can distinguish between policy coordination and regulatory agencies. The former includes the National Energy Council, the Coordinating Ministry of the Economy, and the National Development Planning Agency (Badan Perencanaan dan Pembangunan Nasional). These agencies have considerable leverage, as they report directly to the president and are the main channels to prioritise policy issues. The Coordinating Ministry for the Indonesian Economy was very influential from 2006–2014 when it was the lead agency in coordinating the FTP. Finally, at the micro or project implementation level, PLN buys renewable electricity from IPPs and non-commercial developers. Purchasing decisions on PLN's part and investment decisions on the side of IPPs are by the regulations on IPPs, the general investment laws, the mandated FITs, and the Electricity Law, with the utility acting de facto as the single buyer of private power.

There were various attempts by the government to introduce more market-friendly reforms in the electricity sector (Wells & Ahmed 2007). The last major legislation is Electricity Law No. 30/2009 which reaffirms the monopoly of PLN on the transmission and distribution side but allows for limited participation of IPPs in the generation market. Specifically, PLN owns electricity transmission and distribution assets and operation, but on the generation side every holder of an 'Electricity Supply License' is allowed to supply power for the area for which the license is granted. However, PLN has the 'first right of refusal' to provide power supply in designated areas. This means that PLN controls access to all five existing national grids and has first choice of which off-grid areas to serve before an IPP or any non-PLN entity can enter. In essence, PLN holds

[60] The hierarchy of Indonesian legal instruments is as follows:

- the Constitution of 1945
- laws (Undang–undang (UU)) enacted by DPR (called the House of Representatives)
- Governmental regulations (Peraturan Pemerintah (PP))
- PDs (Peraturan Presiden)
- Ministerial decrees (Peraturan Menteri)
- Regional regulations (Peraturen daerah).

Additionally, there are Presidential instructions (Instruksi Presiden) and circular letters. In general, UUs are written only in general terms and provide brief guidelines. The implementing regulations issued by the government, ministries, and president provide the details and technicalities necessary to make the laws operational.

a de facto monopsony (i.e., is a single buyer in all grids it controls), thus requiring PPAs to be signed between the utility and any project developer feeding into the grid.

A major implication of this structure is that PLN is accountable to three government agencies, which share oversight and regulatory functions over the utility. First, MEMR acts as the main agency to regulate the power sector and sets the national electrification and energy mix targets for PLN to comply with. The Ministry issues the electricity business licenses to PLN, other government entities (such as regional SOEs) and prospective IPPs. It plays a significant role in coordinating the planning process for the National Energy Plan (Rencana Umum Energi Nasional (RUEN)) which sets national electrification and energy mix targets, including RE and efficiency programs.

Second, the Ministry of SOEs (MSOE) has the main oversight function over PLN, as it is also its main shareholder. PLN must report its key performance indicators to MSOE on an annual basis, focusing specifically on financial prudence, electrification and generation expansion targets.

Third, the MoF must compensate SOEs for any PSOs met under the SOE law. The MoF transfers the electricity subsidy to PLN via the MSOE and must justify the size of the electricity subsidy to the DPR.

This means that any incentives for PLN to invest in RE—either as a buyer from IPPs or as a project developer itself—are constrained by its obligation to increase the electrification ratio and meet generation capacity targets at the least cost.

5.3.2 Tariffs, subsidies and financial governance of PLN

Three different phases can be distinguished to describe the evolution of the electricity tariff and subsidy scheme.

5.3.2.1 Informal tariff and subsidy mechanism, 1960–1985

The first phase, from 1960–1985, saw the adoption of policies that provided direct and indirect (hidden) subsidies to prop up PLN's internal finances. Despite officially adhering to a principle of 'cost accounting (full cost pricing) without subsidy', McCawley (1970) showed that hidden subsidies took the form of extremely low capital charges in the books of PLN. These low capital charges did not reflect real costs of capital employed during the production and distribution of electricity. The government did not receive interest on capital and PLN did not generate sufficient internal revenues to cover depreciation and create surplus to build up reserves. Thus, PLN had to resort to ad hoc strategies to save more on maintenance expenditure, effectively through capital consumption, which in the longer run had to be financed by further government support or external funds. Consumers were also indirectly subsidised, as they paid tariffs that do not reflect these costs (McCawley 1970, 1978).

5.3.2.2 First comprehensive electricity law formalises tariff policies, 1985–1998

The second phase, 1985–1997, initiated by the enactment of Electricity Law No. 15/1985, saw efforts of reforming the tariff system to mitigate PLN's financial burdens. Law No. 15/1985 provided tariff-setting regulations for the first time. That law was followed by GR No. 10/1989, which mandated that the president determine the electricity tariff based on a proposal of the Ministry of Mines and Energy. GR No. 17/1990 was then issued to state that the design of tariffs needed to take account of both the public interest and the commercial viability of PLN. However, as previously mentioned the regulations were not specific on how to achieve these objectives and there were no detailed stipulations on how to set the tariff rates.

In the 1990s, the arrival of IPPs provided much-needed additional investment to meet rapid electricity demand (Wells & Ahmed 2007). PLN was expected to ensure investors of its ability to pay for electricity purchased. The government reformed the tariff system to ensure that PLN's revenue stream was sufficient. It introduced TDL and established the Electricity Tariff Adjustment Mechanism, which allowed MEMR to adjust electricity tariffs every three months. Tariff adjustments were made based on changes in the following variables: fuel prices, PLN's purchase price of electricity from IPPs, inflation, and the IDR/USD exchange mid-rate (PLN 2011c).

These mechanisms were valid from 1995–1997 and were generally thought to have provided sufficient investment security to IPPs, as evidenced by the fact that 27 PPAs worth US$17 billion were signed by 1998 (Wells & Ahmed 2007). However, the 1998 Asian Financial Crisis caused a rapid depreciation of the Rupiah versus the USD. As many of the contracts were denominated in USD, PLN was not able to meet repayment obligations without enormous tariff increases. Ultimately, this was politically not feasible and Electricity Tariff Adjustment Mechanism was abandoned by the government in December 1997 (Purra 2009).

5.3.2.3 Politicised tariffs and formalisation of PSO mechanism, 1998–present

When Indonesia entered a new era of democracy and decentralisation after the fall of the Suharto regime in 1998, electricity tariff adjustments were adopted on an infrequent basis subject to a more politicised process (Purra 2009). Mindful of popular resistance and electoral cycles, successive governments preferred to keep electricity tariffs low, especially for the majority of low-capacity households. Significant tariff increases happened during the Wahid and Megawati Sukarnoputri governments (1999–2003) and then much later again under President Yudhyono in 2010 when the government increased electricity tariffs at an average of 10.8 per cent compared to the last tariff hike in 2003 (Purra 2009).[61] Further tariff increases were introduced in 2013 and then continued by the government of President Joko Widodo. From 2014–2017, electricity subsidies were fully abolished for high-end consumers, while low-income residents and small enterprises are still enjoying subsidy support.

This period can also be characterised by making the PSO an explicit legal requirement. For a long time, the government addressed the financial problems of PLN on an ad hoc basis, using the electricity subsidy to cover the budget of PLN. In this sense, PLN has to some extent always operated in a SBC environment, meaning that the utility would know that its losses would be fully compensated. Implicitly, the provision of an electricity subsidy meant a commitment to provide a PSO in the sense that the government wanted to 'ensure the provision of services of general interest not through full market competition' (Lakatos 2004), but by assigning these tasks to selected agents such as SOEs.[62]

Law No. 19/2003 on State Owned Enterprises (the PSO Law) formalised the commitment of the government to provide financial support to PLN's budget. Specifically, Article 66, Paragraph 1 stated that the government is obliged to compensate SOEs—including

[61] The relevant legal instruments were PDs No. 48/2000 and 83/2001

[62] I will follow the definition provided by Lakatos (2004) which defines 'services of general interest as covering market and non-market services which the public authorities subject to specific public service obligations.

PLN—for any losses arising out of mandated service obligations. In effect, Law No. 19/2003 added a PSO margin to the electricity subsidy.

5.3.3 Financial performance of PLN

How have these various tariff and subsidy regimes affected the financial performance of PLN? In this section, available data from 1990–2015 are used to analyse how these constraints have affected the utility's long-term financial performance and investment resources.

Before the 1998 Asian Financial Crisis, annual net income from operations was positive with revenues from the sale of electricity constituting the single largest revenue item.[63] Expenditures were kept closely below revenues resulting in an average annual net income of 1.3 trillion IDR in 1990–1997 (see Figure 5.1 and Appendix 5.2). This suggests that tariff levels were just adequate to create sufficient revenues to cover costs.

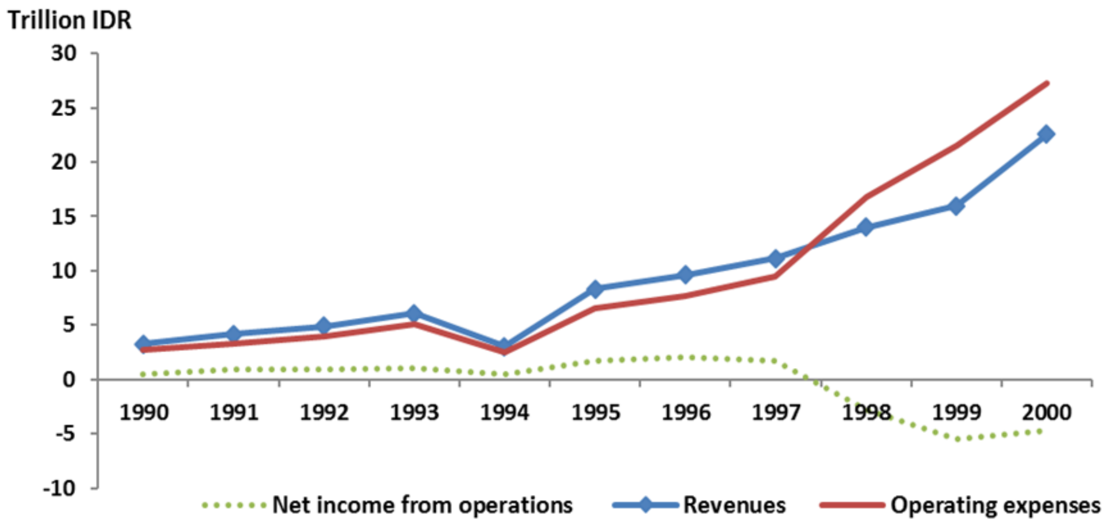
However, Kristov (1995) provided a quantitative assessment of hidden subsidies in PLN's finances. The paper looked at the yearly income statements of PLN from 1980–1992 and recalculated the accounts by revising interest expenses upwards and including market rates of return to equity. The former corrects for the historically low interest rates that PLN enjoyed because the government absorbed all the exchange risk associated with foreign loans. The latter revision accounts for the fact that a large part of the government's subsidies takes the shape of state equity, and the inclusion of a competitive rate of return to equity reflects the opportunity costs of the government's investment. In addition, exchange rate fluctuations were also included. Kristov's (1995) study found that the average retail price per kWh should have been 46% higher in 1980–1994 than stated in PLN's official accounts (Kristov 1995; McCawley 1978).

The Asian Financial Crisis and the drastic devaluation of the Indonesia Rupiah exposed PLN's vulnerability, because much of its debt were denominated in USD while much of its revenues and operating expenses had to be paid in the domestic currency. Operating and debt servicing costs spiralled out of PLN's control and were mainly driven by fuel expenditures. The operating ratio (expenses/revenues) increased to above 100 per cent

[63] Net income is also referred to as earnings before interest and taxes, a common indicator to measure a firm's profitability.

and the debt service coverage ratio (DSCR) fell below 1 (Appendix 5.5 and Figure 5.4 further below).

Figure 5.1: PLN Income trends (1990–2000)



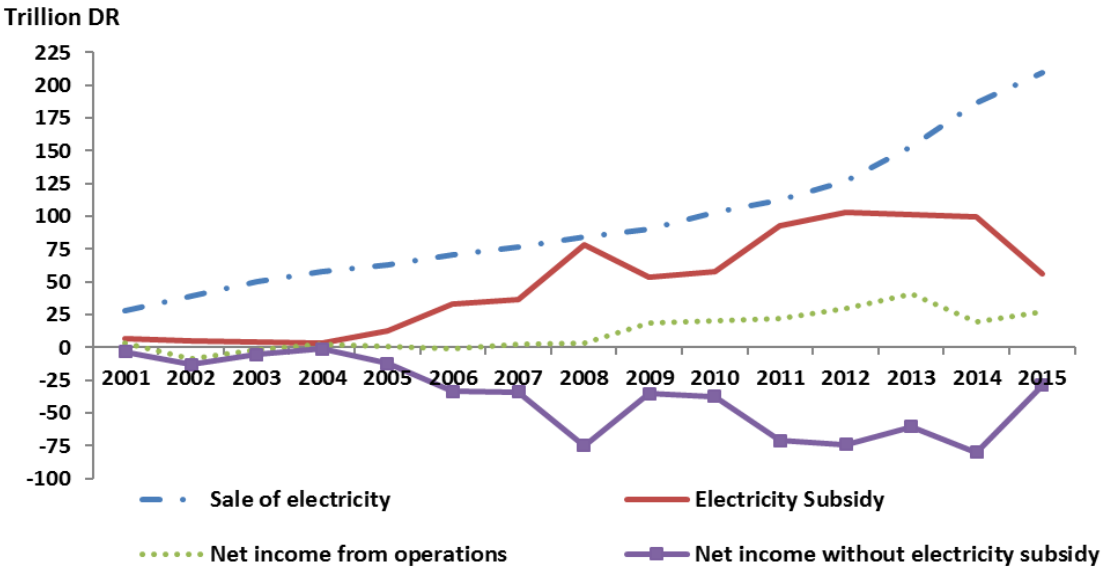
Source: PLN Financial Statements (various years) (see Appendix 5.2).

From 2001 onwards, PLN revenues have become dependent on the electricity subsidy to varying degrees. Total electricity subsidies increased from 6.7 trillion IDR in 2001 to a peak of 103.3 trillion IDR in 2012 before going down to 56.3 trillion IDR in 2015. The share of the electricity subsidy in total revenues increased from 19 per cent in 2001 to 44.4 per cent in 2012 and decreased to 20.6 per cent in 2015. The peak of the share of subsidy in total revenues occurred in 2008, when it reached 79 trillion IDR or around 48 per cent of total revenues for PLN. In 2005, the government removed the fuel subsidy for PLN, resulting in an increased fuel supply cost for the utility. This resulted in significant increases in the electricity subsidy in 2005 and 2006 (see Appendix 5.3 and Figure 5.3).

Net income has become consistently positive since 2006 and increased significantly since 2009 due to the increase in the subsidy. Total net income fluctuated between small losses and profits until 2006 before turning positive, climbing from 3 trillion IDR in 2007 to almost 30 trillion IDR in 2012. While most of the revenues were driven by electricity sales, the government subsidy has become an increasingly important revenue item. If subsidies were not included, PLN would record steady annual deficits ranging from 3 trillion IDR in 2001 to almost 74 trillion IDR in 2012 and 28 trillion IDR in 2015 (see Figure

5.2 and Appendix 5.2). To keep net income positive, the utility depends to a large extent on the government subsidy, with large-scale investment dependent on borrowing from external sources.

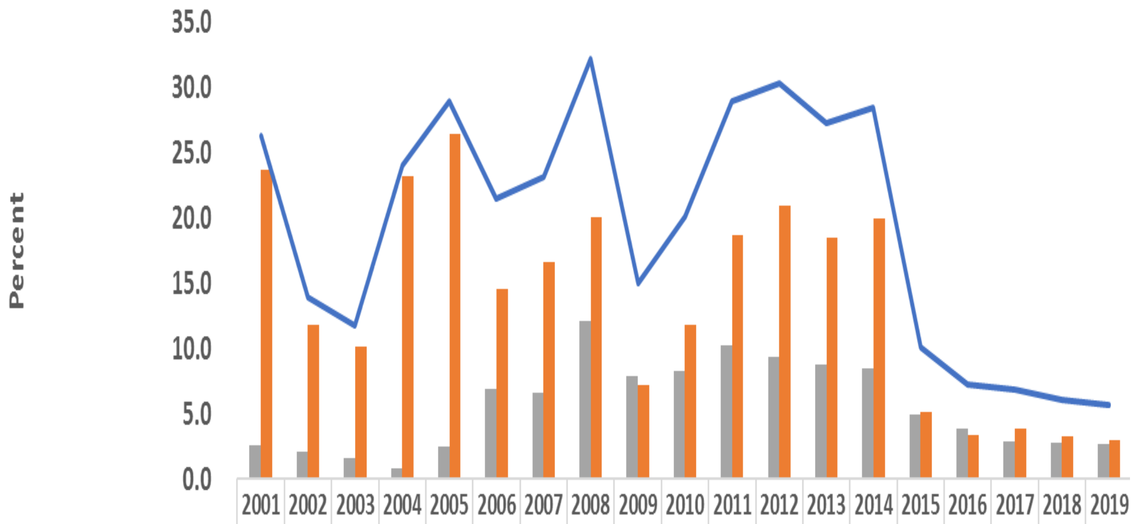
Figure 5.2: PLN income trends (2001–2015)



Source: PLN Financial Statements (various years) and Tables A2 and A3 in Appendix 5.3.

The electricity subsidy is a significant share of the energy subsidy in the central government expenditures, with two noticeable trends in the period 2001–2015, for which realised and audited data are available. Until 2014, total energy subsidies made up, on average, almost 24 per cent of central government expenditures, with fuel subsidies averaging 17 and 6 per cent respectively. After the Jokowi Government made radical cuts to fuel subsidies and phased in higher electricity tariffs in 2014, the share of energy subsidies fell sharply to 11 per cent in 2015, aided by a sharp fall in world oil prices. Revised and projected figures went down to below 5 per cent for both fuel and electricity subsidies. Energy subsidies have been dominated by fuel subsidies, with fluctuating international oil prices periodically affecting the size of the domestic energy subsidy. However, since 2015, fuel and electricity subsidy numbers have almost converged in terms of absolute numbers and relative shares (see Figure 5.3 and Appendix 5.4).

Figure 5.3: Energy subsidies (realised, % of central government expenditures) (2001–2015)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Electriciity subsidies	2.6	2.1	1.6	0.8	2.5	6.9	6.6	12.1	7.9	8.3	10.2	9.4	8.8	8.5	4.9	3.9	2.9	2.8	2.7
Fuel subsidies	23.7	11.8	10.1	23.2	26.5	14.6	16.6	20.1	7.2	11.8	18.7	21.0	18.5	19.9	5.1	3.3	3.9	3.3	3.0
Energy subsidies	26.2	13.9	11.7	24.0	28.9	21.5	23.2	32.2	15.0	20.1	28.9	30.3	27.3	28.4	10.1	7.2	6.8	6.1	5.7

Note: 2005–2015 audited data; 2016 revised data; 2017–2019 proposed (see Appendix 5.4).
Source: Budget (APBN) statistics.

What drives PLN's expenses? On the expenditure side of PLN's income statement, fuel and electricity purchases constitute the biggest items. The former constituted an average of 50–60 per cent of total expenditures, while the latter made up around an average of 15–20 per cent of overall expenditure in 2001–2015 (see Appendices 5.2 and 5.3).[64]

Seen from a financial risk perspective, what can we say about PLN's debt exposure and capacity to borrow money to invest in the power sector? The balance sheet side shows that PLN went through several trends and phases from 1990–2015 (see Figure 5.4 and Appendices 5.5 and 5.6).

In the early 1990s, PLN showed solid finances with low operating, debt/equity and short-/long-term debt ratios before the 1998 Asian Financial Crisis. From the mid-1990s these

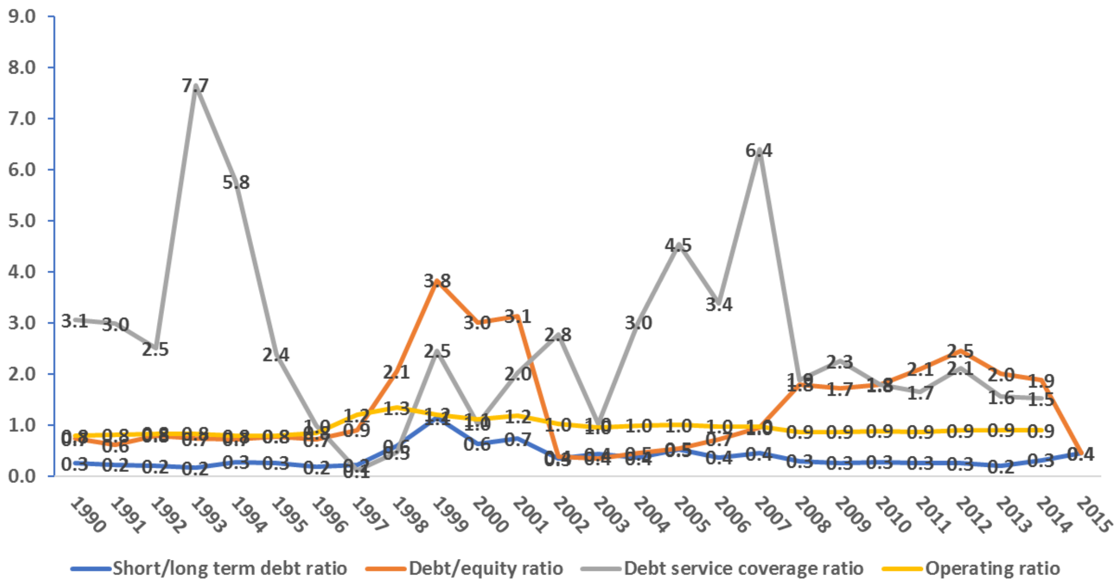
[64] It must be noted though that PLN made a change to its accounting system in 2011, when it decided to reclassify 'purchase of electricity' not as an expenditure item but as 'financial lease' and 'interest expense' items. The utility argues that the change was necessary to reflect the Indonesian Accounting Standards Board's (Pernyataan Standar Akuntasi Keuangan) recommendation that certain power contracts between PLN and IPPs contained leases that should be treated as financial leases (PLN 2012a, p. 137, Note 58). As a result, the share of 'purchase of electricity' in the income statement significantly reduced after 2010.

ratios started to rise, together with declining DSCR, peaking with the advent of the Asian Financial Crisis.

Recovering from the crisis, the first half of the 2000s saw PLN's finances showing relatively high operating ratios, negative and very low rate of returns, and DSCR recovering. Debt to equity ratios fell sharply after the crisis, as PLN managed to settle debt negotiations with external investors.

Finances consolidated between 2005 and 2008, with stable operating ratios and steady increases in the RORs, the self-financing ratio and the DSCR (see Appendices 5.5 and 5.6).

Figure 5.4: Selected financial indicators of PLN (1990–2015)



Source: PLN Annual Statistics (see Appendices 5.5 and 5.6).

However, in the period 2009–2015, most financial indicators worsened until 2012 before recovering slightly. The debt/equity approached pre-crisis levels again, with DCSR and self-financing ratio also declining up until 2012. By 2015, these financial indicators had improved in line with improving net income flows and operating ratios.

A legacy from the Asian Financial Crisis is that PLN is cautious about entering loan and PPA agreements that unfavourably allocate exchange rate risks to the utility (Wells & Ahmed 2007). Short-term loans denominated in USD contributed significantly to the deteriorating financial position of PLN (Purra 2009; Wells & Ahmed 2007). Since the crisis, PLN has managed to reduce the proportion of short-term loans, but more recent figures for 2014–2015 showed an increase to above pre-crisis levels again (see Figure 5.4). However, PLN still has to bear exchange rate risks, with net exchange rate losses having accumulated to around 65 trillion IDR (US$5 billion at exchange rate of 13,300 IDR/USD) during 2000–2015 (PLN 2016a). In 2013, net losses stood at around 48 trillion IDR (US$4 billion), the highest since 1998 (PLN 2013).

From a global point of view, PLN is considered to be a safe borrower, as perceptions of rating agencies have improved over time. Both Moody and Fitch, for example, rated PLN's credit performance as stable and positive in the period 2014–2016, more or less in line with the country's overall sovereign rating. A common theme among the various credit agencies is that while there are concerns about PLN's financial position due to low net income flows, moves towards reforming the tariff system and government support to subsidise the state utility provide enough grounds to provide secure credit ratings.

From a project-level perspective, allocation of exchange rate risks between PLN and IPPs have a significant bearing on PPA negotiations. It should be noted that the regulations do not specify whether under the PPA BPP costs are USD equivalent based or Rupiah based. In practice, PLN prefers Rupiah-denominated contracts, but many RE projects do depend heavily on imported equipment and prefer USD-based costs (Baker McKenzie 2017).

MEMR MR No. 3/2015 determines the maximum PPA tariff for power projects with the following formula:

$$P(t) = P(n) *[0.75 + 0.25*(USPPI(t)/USPPI(0)]$$

For geothermal power projects the formula is slightly different (ADB & World Bank 2015, p. 46):

$$P(t) = [(1-\alpha)*P(0)] +[\alpha P(0)USPPI(t)/USPPI(0)$$

where

P(t) = Tariff in year t, in US cents/kWh

P(0) = Base tariff at COD = Tariff bid at time of tender in year (0)

P(n) = Base tariff at current time

USPPI(t) = United States Producer Price Index for year (t)

USPPI(0) = United States Producer Price Index at time of tender (0)

α = Coefficient based on ad hoc negotiations, estimated cost attributable to post-commissioning OM.

5.4 Implications for renewable energy investment

The prevalent subsidy and tariff regime work against renewables in the following ways. First, the utility's budget process, specifically the determination of the subsidy, is subject to a political process, which does not prioritise investment in RE. Second, given that the subsidy is such a significant part of PLN's revenues, the size of the subsidy and the PSO margin raise investment uncertainty about the utility's general commitment to take up large-scale projects, including renewables. Third, as a result, PLN's financial conditions do not allow for PLN to invest heavily in renewables, thus requiring private sector investment to fill the gap, but which has for a long time not been sufficiently incentivised to respond in sufficient numbers.

5.4.1 A political budget and subsidy regime that does not prioritise renewables

The subsidy and tariff regimes are subject to a political process that does not prioritise renewables. With the utility being the single buyer on the national grids and PLN's revenue coming to a significant extent from the electricity subsidy, investment into expansion of generation capacity depends to a certain extent on the credibility of the government's commitment to bail out PLN in a predictable manner.

However, the enactment of PSO Law No. 19/2003 is not an automatic subsidy transfer mechanism that guarantees a secure investment margin to PLN. In Law No. 19/2003 on SOEs, it is not mentioned how and to what extent PLN is entitled to a full compensation or a margin. While the Laws on State Finances (UU No. 17/2003) and Treasury (UU No. 1/2004) focus on the overall state budget framework (elaborated on below), they do not provide specific guidance on electricity subsidies. The only regulations dealing directly with electricity subsidies are MRs No. 111 and 162/2007 issued by the MoF. These describe the technical process of calculating and determining electricity production costs (BPP), tariff levels and the electricity subsidy. The regulations also mention that a margin has to be added to the BPP estimates ('BPP + margin').

In fact, only since 2009 has the PSO margin been recorded in PLN's (2009, pp. 100–101). The DPR and the government agreed to provide PLN with an investment margin, amounting to five per cent in 2009 and eight per cent in 2010 and 2011. In 2012–2015, the investment margin was reduced to seven per cent (PLN 2013, 2015).[65]

Moreover, the annually-negotiated PSO margin is not the only source for financial support for PLN. In 2011, the government issued PR No. 8/2011 to instruct the Indonesian Investment Agency (*Pusat Investasi Pemerintah*), a unit under the MoF, to support PLN with cash payment of 7.5 trillion IDR to close the financing gap using the 2010 state budget. This suggests that PLN's finances still need to be backed up by temporary policy measures that fall outside the PSO and tariff process.

Thus, the central point in public policy debate on the energy sector is the political uncertainty surrounding the annual size of the 'PSO margin' or 'investment margin' that PLN is entitled to book as revenues. This uncertainty stems from the unclear legal framework, as there is no single law that governs subsidy policies, but several pieces of legislation that determine the size of the electricity subsidy (see Table 5.1).

The reality is that the electricity subsidy and PSO margin are subject to a complex and politicised fiscal policy framework. This framework has a record of slow budget execution and project implementation (World Bank 2007, 2011a).

[65] See for example, 'PLN's business margin remains at 8 percent', *Jakarta Post*, 27 June 2011; 'PLN allowed to take higher margin in 2010', *Jakarta Post*, 25 August 2009, 'PLN margin drops, impact in 2015', *Indonesia Finance Today*, 24 June 2011, http://en.indonesiafinancetoday.com/read/7092/PLN-Margin-Drops-Impact-in-2015.

Table 5.1: Subsidy-related laws and regulations

Legal instrument	Key issues
Law (UU) No. 19/2003 on State Owned Enterprises, Article 66(1)	Government to support PSO of SOEs with a 'margin' in cases where the PSOs are deemed financially not feasible for the SOE
UU No. 17/2003 on State Finances	Overall public expenditure framework
UU No. 1/2004 on Treasury Article 3 (4)	All government expenditures including subsidies that support central government programs have to be financed by the state budget
MR No. 111 162/2007	Regulates technical process that sets electricity tariffs and subsidies using a 'BPP + margin' approach
PR No. 8/2011	Instructs Pusat Investasi Pemerintah/Government Investment Centre to support PLN with cash payment

Notes: MR = Ministerial Regulation, PR = Presidential Regulation, PSO = public service obligations, SOE = state-owned enterprises, BPP = basic cost of electricity production.

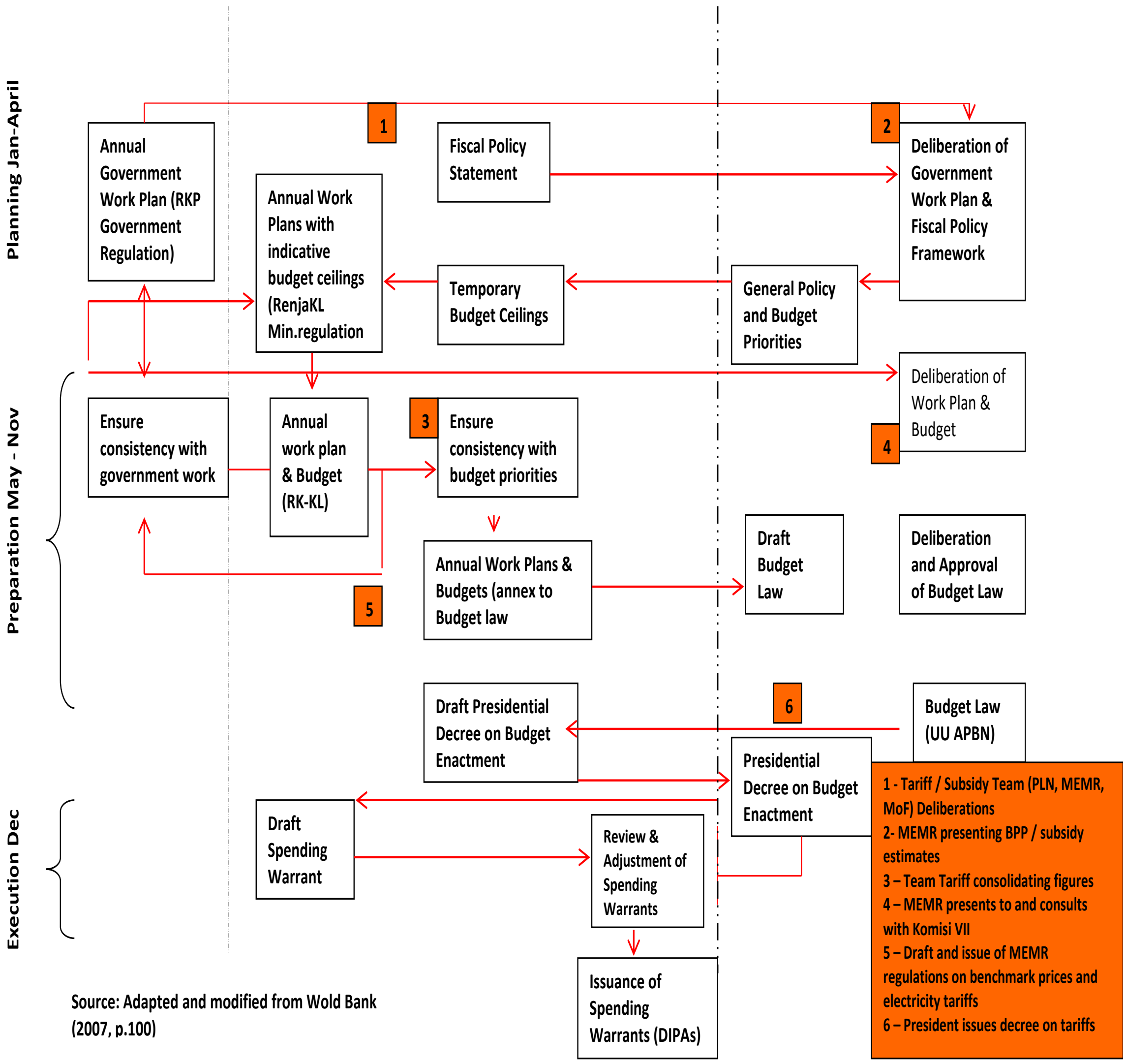
The budget framework is illustrated in Figure 5.5. The process is divided into three phases in each calendar year: planning (January–April), preparation (May–November), and execution (December).[66] In the first phase, BAPPENAS, MoF and the line ministries draft their work plans and agree initial budget ceilings, using the government's annual work plan (Rencana Kerja Pemerintah). They formulate draft work plans, which are then discussed with the DPR. After initial budget ceilings are agreed on, each line Ministry—in this case the MEMR—then prepares its work plan and budget, incorporating the proposed subsidy and tariffs agreed by the tariff team. This document is then checked by DG Treasury for whether it is consistent with spending warrants (DIPA documents) which are also prepared by the MEMR.

In the second phase, the draft DIPAs, the work plan and budgets are then submitted by the DG Treasury as part of the Draft Budget Law. Once approved by the DPR, it becomes the Budget Law (UU APBN). This is followed by a PD on Budget Enactment.

[66] This section follows World Bank (2007, 2011).

In the third and final phase, DIPAs are reviewed, finalised and issued by the DG Treasury. The DIPAs are effectively the permit for government authorities to disburse funds for project implementation (World Bank 2007, pp. 96–99).

Figure 5.5: Flow chart of budget spending process and relevant steps in determining tariffs and subsidies



Notes: MEMR = Ministry of Energy and Mineral Resources, BPP = basic cost of electricity production.

Typically, government spending is slow and budget realisation is low, with most of the spending executed in the last quarter of the year, after the DPR finishes its budget revision in the first half of the year (World Bank 2011a). Factors explaining this pattern of delayed implementation include the reliance on detailed and input-focused documents; inadequate capacity in managing the procurement process; audit procedures that are constrained by overlapping activities of three internal audit agencies; and the powerful role of the DPR resulting in discussions that tend to focus on details and not on overall allocation, political priorities and objectives. These cause frequent complicated and lengthy revision processes (World Bank 2007, 2011a).

The PSO margin and tariff mechanisms should be seen within the context of the budget planning and implementation cycle (see Figure 5.5). Negotiation on draft tariff rates and electricity subsidies between PLN and the inter-departmental tariff team start in February.[67]

First, PLN submits a proposal containing its projected BPP calculations, which serves as the basis for calculating the subsidy and tariffs. Second, the proposal is evaluated by the MEMR and the MoF, and subsequent negotiations and revisions are handled by a so-called tariff team (*Tim Tarif*) consisting mainly of staff and officials from PLN, MEMR and MoF. Third, the tariff team then agrees on the draft tariff rates and estimated size of the subsidy. Fourth, once the DPR has approved the draft rates, a final evaluation is conducted by the MEMR and the tariff team, and this is incorporated into the MEMR's annual work plan and budget document, which is then subject to subsequent steps in the budget approval process, as described above.

However, the process of determining the tariff rates is based on drafting two separate MRs. First, the MEMR is in charge of drafting the MR on electricity tariff rates, which has to be approved by the president. Second, the MEMR issues the decree on 'benchmark prices of certain types of oil fuels.' This decree is a prerequisite to calculate the energy subsidies in the state budget. Late issuance of the decree by the MEMR will delay the subsidy realisation process.[68]

The heavy involvement of the DPR means that the determination of the tariff rates, electricity subsidy and the PSO margin is a heavily politicised process. Obvious entry points for political interventions are discussions and hearings in the DPR, which are led by the *Commission VII on Energy and Mineral Resources, Technology and Environment.*[69] However, the drafting and planning process within the government bureaucracy itself is open to selected stakeholders from industry and CSOs. For instance, informal hearings with experts outside government are organised by the tariff team to draft the tariff rates

[67] Interview with official from MEMR.
[68] Interviews with staff of Fiscal Policy Office and discussion with MEMR staff.
[69] Interview with Komara Djaja, University of Indonesia, former senior advisor to the Coordinating Ministry of Economic Affairs and former member of Board of Directors at PLN.

and the size of the electricity subsidy.[70] Moreover, industry representatives had significant inputs into the drafting process of purchasing price regulations for RE in.[71]

According to PLN's interpretation, the existing PSO margin and subsidy regulations are not enough to allow PLN to fulfil its PSO objectives. PLN argues that the PSO 'investment margin' is not big enough to allow the utility to fulfil its public service obligations, which include annual electrification targets and associated investment costs. The current practice only allows for coverage of the operational expenses. Thus, the central government does not really adhere to the PSO law, as it never fully compensates the utility for upholding its PSO function.[72]

Policymakers at PLN argue that the PSO margin is important in making investment choices between renewable and non-renewable electricity generation. As a rule of thumb, investment outlays for capital expenditures associated with RE projects in geothermal and large hydro are at least twice as high when compared to conventional fossil fuel and natural gas-based ones. On the other hand, operational expenditures tend to be far lower in RE projects in the longer term. For PLN, the size of the PSO margin has a direct bearing on investment in capital-intensive projects. The larger the PSO margin, the more PLN is inclined to invest in riskier and capital-intensive RE projects. Thus, from the utility's perspective, the PSO margin helps to reduce the larger risk associated with higher capital costs of renewable electricity generation, while the electricity subsidy alone covers the BPP on the operational expenditures side.[73] Overall, the implication is that the PSO subsidy regime subjects PLN to degree of 'short-termism' in the sense that the utility is focusing on getting by and the size of the subsidy does not really allow for big investment into capital-intensive renewables with large upfront costs.

All of this suggests that, from a PLN perspective, the size of the PSO margin is an important factor in deciding whether to buy more renewables at prevailing FIT regulations. For example, interviewed policymakers at PLN argue that the existing FIT regulations are not FITs in the strictest sense, but 'are conceptually moving in the

[70] Interview with staff expert in MEMR and presentation material from MEMR. Interview with staff expert working for DPR commissions VII.
[71] Interview with representative from METI.
[72] Interview with Setio Anggoro Dewo, PLN Finance Section and Rahman Mohamad, PLN, Head of Renewable Energy Section.
[73] Interview with Setio Anggoro Dewo, PLN Finance Section and Rahman Mohamad, PLN, Head of Renewable Energy Section.

direction of a feed-in tariff'.[74] As applied in other countries, a FIT would make it an obligation for PLN to buy electricity at a fixed price. However, this is not the case in Indonesia, at least not for the geothermal FIT under MEMR MR No. 32/2009. According to PLN's understanding, the FIT is a ceiling price, especially for geothermal power. For RE below 10 MW, the existing FIT regulations are functioning in a way that is closer to a FIT in the strict sense.[75] This hesitation of PLN policymakers to apply the existing FITs in a strict sense implies that they are concerned that the costs of buying renewables could not be subsidised under the PSO Article 66 in Law No. 19/2003. In short, the smaller the PSO margin, the less inclined PLN is to invest in renewables, thus undermining the effectiveness of FIT regulations.

Conflicting internal objectives might also contribute to PLN's reluctance to purchase RE. Observers note that the Board of PLN is accountable to the MSOE and is assessed by an annual performance review. The internal key performance indicators against which the PLN Board is assessed might not contain sufficient incentives to make the increase of the share of RE in PLN's supply mix a prime objective. Thus, PLN faces not only external public pressures in the form of DPR and the MoF to make its operations more efficient, but also 'internal' pressures to achieve certain annual electrification objectives. Given that PLN already faces pressures to resolve frequent blackouts, the utility will be more inclined to use quick oil- and diesel-based electricity purchases to meet demand, rather than investing in renewables.[76]

From a private investment perspective, the existing regulations do not provide sufficient certainty about PLN's capacity and commitment to buy private electricity. This is evidenced by the fact that the MoF had to issue MR No. 77/2011 to state financial support to PLN. This regulation states that the Government of Indonesia guarantees the business viability of PLN when the utility enters contracts with IPPs. The regulation supports the implementation of FTP 2 under PR No. 4/2010.

However, this regulation contains several limitations from the perspective of private investors. First, this regulation is not a blanket guarantee covering all power projects,

---

[74] Interview with Setio Anggoro Dewo, PLN Finance Section and Rahman Mohamad, PLN, Head of Renewable Energy Section.
[75] Interview with Setio Anggoro Dewo, PLN Finance Section and Rahman Mohamad, PLN, Head of Renewable Energy Section.
[76] Interviews with Komara Djaya, University of Indonesia and Mike Crossetti, Director Castlerock.

but the Viability Guarantee (VG) can only be obtained on a case-by-case basis for power projects. Second, only projects submitting a feasibility study and that have reached the financial stage can obtain the guarantee, meaning that projects in the exploration stage are not covered. Third, in case the VG might contribute to fiscal risks and endanger the state budget, the government can refuse the VG, even if all other criteria have been fulfilled by the IPP. Fourth, related to the former point, PLN needs to notify the MoF (the DG of Loan Management and then DG of Budget) one year in advance if a financial shortfall will be claimed by PLN. This effectively means that PLN and IPPs need to wait for at least one year for settlement of claims to be settled, as they need to be included in the state budget (Baker McKenzie 2017).

Overall, the VG under MR No. 77/2011 is considered a weak instrument by private sector players, especially compared to the MoF letters supporting IPP projects before the Asian Financial Crisis (Baker McKEnzie 2017). Interviews with stakeholders suggest that this regulation improves legal certainty for PLN but not IPPs, as there is no right of direct recourse for IPPs against the government and it is effectively only a guarantee to PLN. The VG is a letter to PLN stating that the government guarantees PLN's ability to fulfil its payment obligations under the PPA in case of a 'shortfall'. Moreover, there are significant risks beyond the risks of non-payment by PLN which are not covered by the guarantee. Specifically, risks in the period before commercial operation take off are still perceived as high by geothermal investors.[77]

In August 2016, the government announced a new Government Guarantee program for projects under the 35 GW program (MoF Reg. No. 130/PMK.08/2016). This new initiative provides loan guarantees to financial institutions that provide financing to PLN and business feasibility guarantee to IPPs that partner with PLN. This should further reassure investors on PPA creditworthiness.

5.4.2 Non-transparent information on electricity supply costs

The lack of transparency on the costs of electricity supply further compounds the uncertainty associated with the political process of determining tariff and subsidy levels. Differences in electricity supply cost data (BPP, biaya pokok produksi) raise some doubts

[77] Interview with MEMR staff and Alex Smille, Star Energy.

over the appropriate size of the subsidy. Information on electricity production costs can vary between government agencies. In Table 5.2, PLN, MEMR and figures audited by BPK have different estimates on the BPP, at least for the period between 2003 and 2015 for which data from all sources are available. When using average generation costs in PLN Annual Statistics, costs are generally lower than figures used by MEMR.

Although the calculations in Table 5.2 are only illustrative, this difference in the electricity supply cost estimates between PLN and MEMR indicate diverging assumptions used. In 2008, the discrepancy in BPP estimates was notably big and well documented in public statistics. Average generation costs in PLN Annual Statistics show a cost of 1,051 IDR/kWh, but MEMR MR No. 269/12/26/600.3/2008 shows a national BPP of 1,649 IDR (see Table 5.2). The difference points to PLN's use of average costs as least-cost estimates, while the MEMR/BPK figures are 'cost-plus' estimates, which come closer to the realised subsidy figures.

The difference between the 'entitled' subsidy and the actual subsidy received by PLN shows that the state utility can rely on a constant revenue stream in the form of the government subsidy. Since 2005, the gap between the disbursed subsidy and the estimated needed subsidy has been positive. This indicates that PLN was successful in securing a sufficient PSO margin, as stipulated by the law.

The question arises whether these discrepancies in electricity supply cost estimates are inherent in a politicised budget and subsidy calculation process, which might point to agency and asymmetric information problems between the various government agencies and PLN.

On the revenue side, projected targets of electricity sales volumes are formulated by PLN and MEMR, and then discussed with the MoF. Negotiations are driven mainly by the state budget assumptions on GDP growth, international oil prices and energy elasticities. The electricity sales projections form the base to calculate the expected revenues to PLN (see Figure 5.7).[78]

[78] The determination of the tariff and subsidy process are laid out in MoF MR No. 111 and 162/2007.

Table 5.2: Supply costs, tariffs and estimated size of electricity subsidy

Year	Average BPP (IDR/kWh)		Avrage TDL (IDR/kWh)	TDL-BPP (IDR/kh)		GWh sold	Entitled subsidy (Trn IDR)		Actual subsidy (Trn. IDR)	Gap (Trn. IDR)	
	[1]		[2]	[3] = [2]-[1]		[4]	[5] = [3]x[4]		[6]	[7]=[6]-[5]	
	PLN	MEMR/BPK*		PLN	MEMR /BPK*		PLN	MEMR/BPK*		PLN	MEMR /BPK*
2001	204	na	334	130		84,520	11.0		na		
2002	330	na	448	118		87,089	10.3		na		
2003	339	618	561	222	-57	90,441	20.1	5.2	4.1	- 15.95	-1.06
2004	351	597	584	233	-13	100,097	23.3	1.3	3.5	- 19.79	2.20
2005	470	710	589	119	-121	107,032	12.8	13.0	12.5	- 0.26	-0.45
2006	706	934	622	-84	-312	112,610	9.5	35.1	32.9	23.45	-2.23
2007	707	920	627	-80	-293	121,247	9.7	35.5	36.6	26.95	1.07
2008	1051	1,649	651	-400	-998	129,019	51.7	128.8	78.6	26.93	-50.16
2009	768	1,058	662	-106	-396	134,582	14.2	53.3	53.7	39.46	0.41
2010	796	1,088	703	-93	-385	147,297	13.6	56.7	58.1	44.46	1.39
2011	1051	1,351	802	-249	-549	157,993	39.4	86.7	93.2	53.84	6.46
2012	1217	1,374	802	-415	-572	173,991	72.3	99.5	103.3	31.05	3.78
2013	1207	1399	818	-389	-581	187,541	73.0	109.0	101.2	28.25	-7.75
2014	1297	1420	939	-358	-481	198,602	71.0	95.5	99.3	28.26	3.78
2015	920	1300	1035	114	-266	202,846	23.2	53.9	56.6	33.37	2.70

Source: PLN Annual Statistics except for BPP figures by MEMR (MEMR Presentation 2012) and BPK audited figures (PLN 2015:95)
BPP=Biaya Pokok Produksi, Producion Costs; TDL=Tarif Dasar Listrik (Electricity Retail Price)
* 2003-2008 figures are MEMR figures. For 2008, the offficial average BPP was used, as published in MEMR Ministerial Regulation 269 - 12 /26/600.3/2008
2009-2015 figures: BPK audited figures

On the cost side, PLN starts the process by submitting its proposed BPP estimates to the DGEEU in the MEMR. The BPP is then set according to technology type and incorporates allowable costs. Thus, the calculations do not apply a 'least cost' approach, but a 'cost-plus' method. These allowable costs are determined by the following four main factors: investment costs (element A), fixed OM costs (element B), fuel costs (element C) and variable OM costs (element D). PLN's BPP assumptions form the base for price negotiations with IPPs and these four main elements form the base of each PPA (see Figure 5.7).

BPP estimates for every region are collected and then sent to Jakarta. The MEMR then takes the average which then becomes the national average BPP.[79] These proposed costs are also reviewed by the FPO under the MoF which examines the main macroeconomic assumptions underlying the estimate of the BPP. After revisions, an investment margin is added to the final cost estimates to determine the final subsidy amount (see Figure 5.7).

However, while the formal process does involve a vetting process between PLN, MoF and MEMR, differences in officially available statistics might arise due to different assumptions applied. For example, the MoF and MEMR do not review the BPP based on the efficiency of technology choices or other broader criteria related to PLN's operations (Australia Unlimited 2012, p. 37).

Additionally, the need for PLN to adhere to state audit procedures might create incentives to manipulate cost items and increase the size of the subsidy. The BPK has its own benchmark prices for BPP. These might not align with PLN's own estimates and might not reflect relative costs of different generation technologies. In some cases, PLN has an incentive to pay higher fuel prices to meet BPK price expectations to avoid suspicions of 'fraud' when charging prices lower than higher benchmarked prices (Australia Unlimited 2012, p. 37).

Interviews with policymakers also indicate that negotiations on both the tariffs and benchmark price for oil fuels are very much dictated by international oil price assumptions, which are subject to revisions forwarded by the MoF. These, in turn, affect PLN's estimates on BPP costs, which fall under 'allowable' costs negotiated with the tariff team.[80] Central government expenditures show the extent to which oil price assumptions can significantly affect total spending and subsidy outcomes. In some years, the underestimation of the oil price has led to massive upward revisions and

[79] Interviews with staff of Fiscal Policy Office and MEMR staff, Tariff and Subsidy Section. The subsidy is calculated as the difference between the per unit BPP and the mandated electricity price for consumers (TDL) times the sales volume of electricity. The BPP is calculated for each voltage category. For instance, production costs in the low voltage category (TR= tegangan rendah) is calculated as follows:

$$BPP_{TR} = (Total\cos t_{TR} - Total\,\mathrm{Re}venues_{TR+TM}) \div (kWh_{TR}sold - kWh_{TR}Loss)$$

[80] Interviews with staff from Fiscal Policy Office and MEMR.

increased actual spending on subsidies, for example in the crisis years of 2005–2006 and 2007–2008 (World Bank 2011a, 2011b).

PLN also receives income as offsets against payments made to accounts of the national oil company PERTAMINA. This is part of a complicated settlement process between the government, PLN and PERTAMINA within the state budget framework. The government pays fuel subsidies to PERTAMINA and electricity subsidies to PLN on a monthly basis.[81] Both SOEs have to pay profits and dividends to the government. Domestic fuel consumption is subsidised by the government, but PLN has to pay PERTAMINA for purchasing oil-based fuel at international prices. The difference between domestic and international fuel price—the fuel subsidy—which PLN has to initially pay, is then repaid by the government to PLN as part of the subsidy.

Until 2010, the payment arrangements were complicated by the fact that PERTAMINA has unsettled debt and arrears with the government in the form of unpaid dividends, and non-oil tax and gas revenues. As a result, the government was at times reluctant to pay the fuel subsidy amount punctually, which also affected the fuel supply and payment flow between PLN and PERTAMINA (World Bank 2007).

The electricity subsidy itself is not paid out in full every budget year, which affects PLN's cashflow. The payment process starts with PLN sending a letter of request for payment to the DG of Budget in the MoF who verifies the amount asked for.[82] PLN has to submit realised monthly electricity sales, broken down to the various customer groups and preliminary BPP, also classified into the various tariff groups. Payment of the subsidy to PLN is on a monthly basis. However, only 95 per cent of the monthly electricity subsidy is paid out. The final annual total subsidy amount recorded in the books is determined after the budget has been audited.[83]

In PLN's balance sheet, the utility receives the difference between the amount recognised as revenue and audited subsidy as 'subsidy receivables from previous budget year'. In PLN's view, this practice of reconciling the difference every year is not classed as past dues, meaning that PLN as a borrower does not have to pay any penalties or

[81] Before 2006, the government paid 70 per cent of the budgeted fuel subsidy to Pertamina on a quarterly basis. The switch to a monthly payment system is supposed to improve the cash flow of both SOEs.
[82] The process is described in MoF MR No. 11/2007 and the subsequent amendment contained in MR No. 162/2007.
[83] Interview with staff of Fiscal Policy Office.

additional interest. The utility argues that there is only limited credit risk to subsidy receivables, because the counterpart is the central government (PLN 2016a, p. 75). This suggests that PLN does operate to some extent in a SBC, as it relies on the central government to guarantee its finances.

From the perspective of an IPP wishing to sell renewable electricity, its selling price has to match PLN's BPP, as the utility is the single buyer on the grid. Securing PPAs with PLN, therefore, depends on the utility's assessment of relevant supply costs on a case-by-case basis in different provinces. This assessment, in turn, depends on PLN's budget priorities, which are clearly motivated by least-cost considerations that favour coal-fired generation.

PLN has clearly shifted to coal-based electricity purchases since the mid-2000s, which have overtaken natural gas as a major cost item. The increased expenditures reflect both an increase in the volume of coal purchased and higher world market prices.

However, fluctuating coal prices have raised concerns for PLN to secure sufficient coal supply for coal-fired power plants. For example, as coal prices increased in 2010–2011, domestic coal producers were not happy with the Domestic Market Obligation arrangement, which mandates that coal producers deliver an annual volume quota at lower domestic prices to PLN. The utility had a hard time locking down prices, as intended in the Domestic Market Obligation. Deprived of the opportunity to export more of their output at higher international prices, domestic suppliers have asked for revised terms of references. Consequently, the government has had to mediate talks between PLN and its coal suppliers to finalise prices, a story similar to developments in the energy sector in China (Burke & Liao 2015).[84] It is no wonder that the PLN leadership made plans to invest in own coal production units to secure supply.[85]

The difficulties in procuring coal have caused delays of PPAs of coal-based projects in the FTP 1 and 2.[86] The delay in the completion of the coal-fired plants has also forced PLN to exceed its allocated budgetary quota for high speed diesel in 2011.[87] This

---

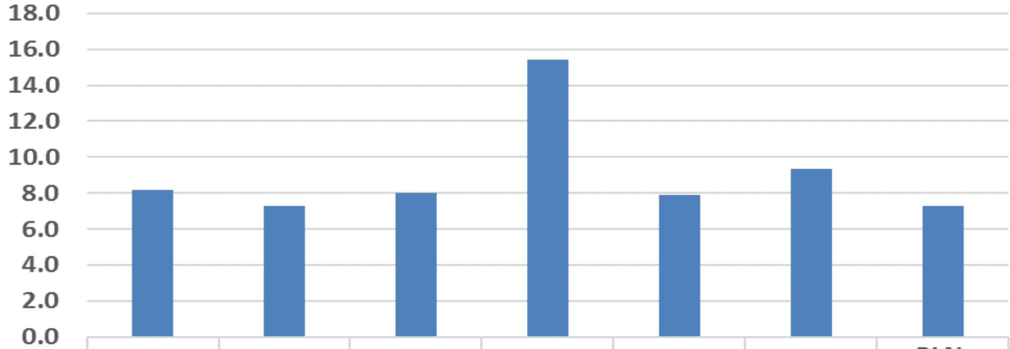
[84] See for instance, 'Government promises coal for PLN despite price spikes', *Jakarta Post*, 24 January 2011.
[85] See 'Coal Rush', *Jakarta Globe*, 30 November 2011.
[86] Interview with Komara Djaya, former official of Coordinating Ministry and PLN board member.
[87] By September 2011, PLN had burned 8.3 million kilo litres of high-speed diesel as of the end of September, or 94 per cent of the 8.8 million kilo litre quota set in its budget for the same year. See 'PLN burns pricey diesel waiting for coal plants to go live', *Jakarta Globe*, 23 October 2011.

continues a longer pattern of increased spending on diesel fuel. Looking at the budgeted items for purchasing of electricity, expenditures for renting diesel generators have grown from around 100 billion IDR in 2001 to over 2 trillion IDR in 2010 (PLN Financial Reports 2001–2010). Much of these purchases go into supplying communities living in the smaller, remote outer islands, which are difficult to access and lie outside PLN's major grid networks.[88] Prolonged declining international coal prices from 2014–2016 have forced the government to mediate between PLN and coal miners to negotiate prices that are acceptable to both parties.[89]

Recent data on mandated tariff rates strongly suggest that policymakers are prioritising PLN's interest in keeping the purchasing prices of renewables in line with the utility's supply costs. Average supply costs (BPP) are estimated to be 9.3 cents/kWh in 2017, with PLN selling electricity for less than 7.7 cents/kWh (see Figure 5.6). All fossil fuel–based electricity and hydropower are priced below the BPP. FIT rates for solar PV were at an average 15.4 cents/kWh under MEMR MR No. 3/2015. However, the most recent regulation in January 2017, MEMR MR No. 12/2017, issued a new FIT for solar PV, determining the purchasing rate for PLN as 85 per cent of BPP. An accompanying MD No. 1404/2017 sets PLN's national BPP at 983 IDR/kWh or 7.39 cents/kWh for 2016. This is clearly a disincentive for solar power developers, undermining much of past efforts to offer attractive FITs for renewables to developers.

[88] Interview Hadi Susilo, PLN Division of Renewable Energy.
[89] See for example, 'PLN, coal companies in talks about prices', *Jakarta Post*, 11 March 2016, http://www.thejakartapost.com/news/2016/03/11/pln-coal-companies-talks-about-prices.html; 'PLN avoids cost-plus coal pricing scheme for 2017 business year', *Jakarta Post*, 8 June 2016, http://www.thejakartapost.com/news/2016/06/08/pln-avoids-cost-plus-coal-pricing-scheme-for-2017-business-year.html.

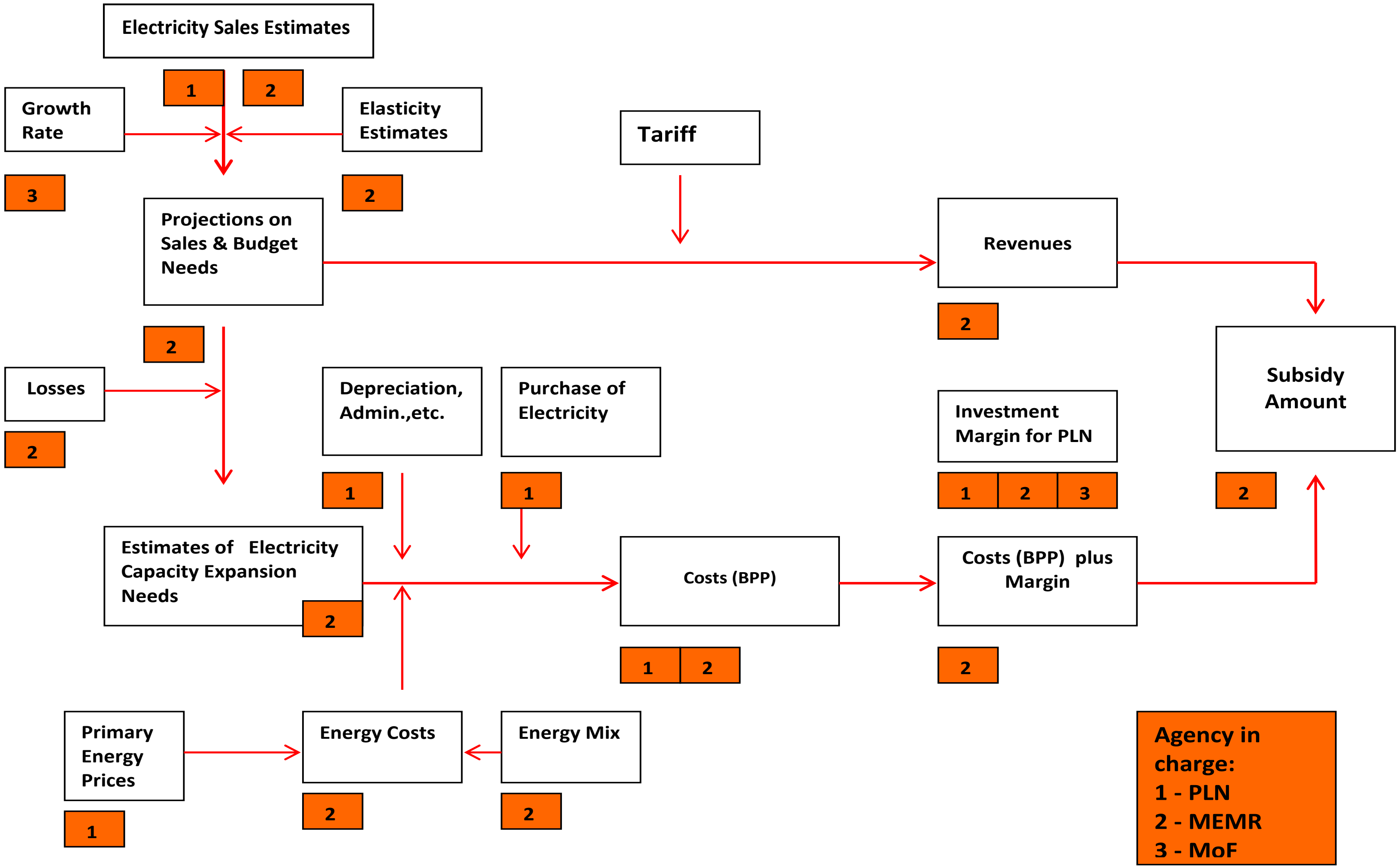
Figure 5.6: Purchasing tariff rates for PLN and supply costs in 2017 (US c/kWh)



	Coal	Gas	Hydro	Solar PV 2016	Solar PV 2017	BPP	PLN Selling price
Tariff rates	8.2	7.3	8.0	15.4	7.9	9.3	7.3

Source: Tariffs for the purchase of coal, gas, and hydro from MEMR MR No. 03/2015. Tariff for the purchase of solar PV is the weighted average of FITs stated in MEMR MR No. 19/2016 and MEMR MR No. 12/2017. BPP are taken from a presentation at 'Solar PV trade Mission Indonesia' conference organised by KfW/DEG, 27 February – 3 March 2017.

Figure 5.7: Flowchart of subsidy calculation process



Source: Adapted from Ministry of Energy and Mineral Resources Presentation (2011) and MR No. 111/2007 and 162/2011.

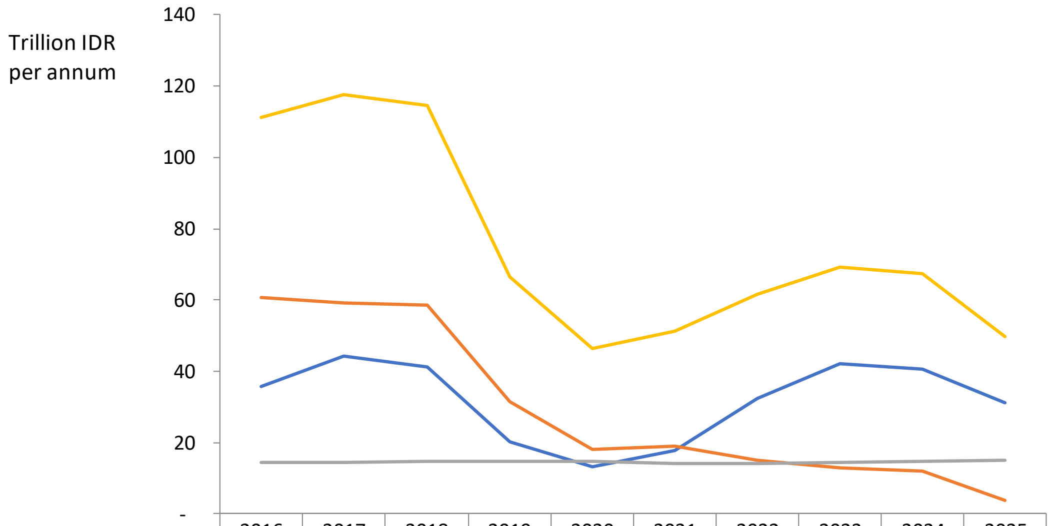
5.4.3 Insufficient investment funds for PLN

PLN faces a significant funding gap to finance future expansion of generation capacities, including renewables. Under the RUPTL 2016–2025 scenario, PLN forecasts additional investment needs of 756 trillion IDR to expand both PLN and IPP generation capacity over nine years (PLN 2016b, pp. 196–197). This would amount to around 84 trillion IDR (or around US$8 billion) per year of investment, which is far above the annual average of 1.6 trillion IDR worth of net income PLN was able to generate in 2001–2015 (see Figure 5.8).

PLN would have to significantly increase its revenues to meet these targets, as illustrated by a simple simulation of its income statement. Under this simulation, the annual investment targets for generation are added to PLN's total revenue stream from 2016 onwards. These would increase the net profits for PLN and the disposable income for the utility to spend.[90] Under a BAU scenario, income from operations would have to rise from 378 trillion IDR in 2016 to 970 trillion IDR in 2025 (see Appendix 5.7).

[90] This income statement simulation ignores financing costs and does not include the financing needs for transmission and distribution. For illustration purposes, the other line items under operating expenses are held constant at 2012 levels. This results in the fall of the operating ratio.

Figure 5.8: Projected investment needs under RUPTL 2016–2025 (business-as-usual)



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Generation	36	44	41	20	13	18	32	42	41	31
Transmission	61	59	59	32	18	19	15	13	12	4
Distribution	15	14	15	15	15	14	14	14	15	15
Total Investment	111	118	114	67	46	51	62	69	68	50

Source: PLN (2016b).

To meet these revenue targets, PLN needs to rely on a combination of increased tariffs and reduced subsidies. Under a BAU scenario, PLN maintains a historical average of 76 per cent of sales revenue and 21 per cent of subsidy in total revenues throughout the 2016–2025 period. Given the targeted electricity sales targets over the same period, tariffs would have to grow by 30 per cent in 2016–2025.

In the alternative scenario, the share of the subsidy would be reduced and then abolished, while the share of revenues from sales increases. The share of revenues from the sale of electricity would gradually increase from 76 per cent in 2016 to 85 per cent of PLN's income statement in 2025. The share of the electricity subsidy starts at 21 per cent in 2016 and is gradually reduced and abolished by 2022. This scenario requires tariff levels to increase by almost 40 per cent over 2016–2025 (see Figure 5.9 and Appendix 5.8).

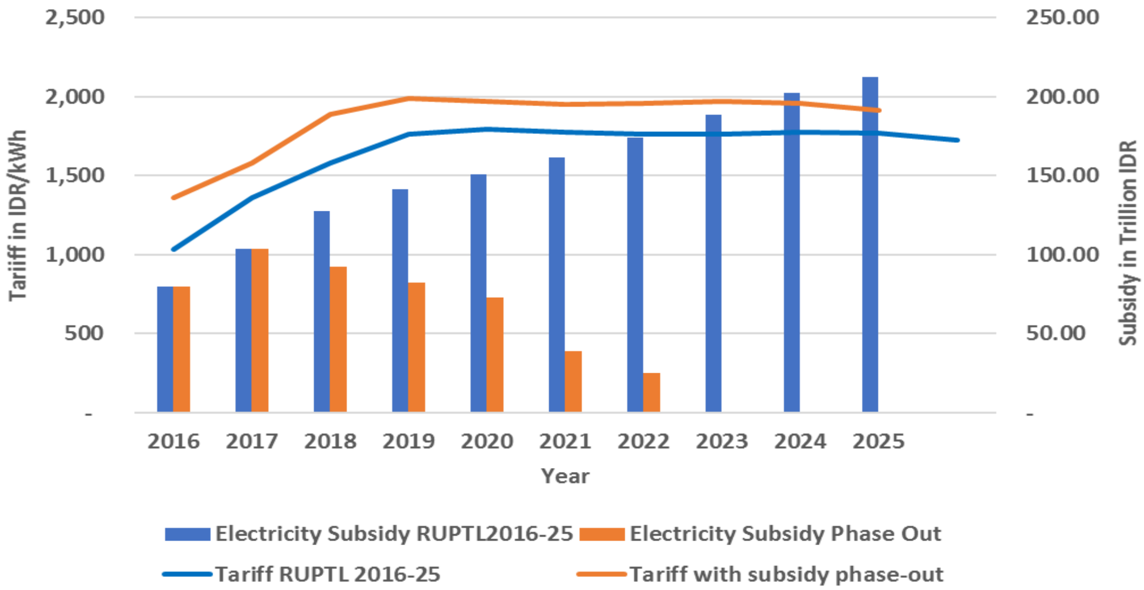
The latter scenario comes close to the government's proposed roadmap to reduce the electricity subsidy in 2015–2019. Under this plan, gradual tariff increases for all consumer categories are phased in over this period, with subsidies abolished from 2018 onward for all but the lowest income categories. Tariffs will be increased based on an Automatic Tariff Adjustment Mechanism, applied monthly for most consumer classes

(Asian Development Bank 2016, p. 12). The reduction in subsidies and the increase in tariffs might also increase the space for PLN to increase investment. Burke and Kurniawati (2018) suggest that electricity demand is price inelastic in Indonesia, so subsidy reductions from 2013–2015 have reduced overall electricity demand. The implication is that PLN faced less pressure to invest in upgrading generation capacity and freed up resources to invest in other types of infrastructure. This might boost the prospects of PLN taking up more renewables (Burke & Kurniawati 2018, p. 417).

PLN can also use debt financing—such as bonds—to borrow from the government and the capital market.[91] The discussion on debt in the previous section has shown that the utility has improved its financial conditions significantly since the Asian Financial Crisis, but it is still limited—given that PLN's budget is subject to a political process—to raise the needed funds solely from government budget and state-owned investment sources. For the 35 GW expansion program in 2015–2019, it has raised some funds through the state budget and from loans, but still faces a funding gap of 392 trillion IDR (US$30.2 billion) (Asian Development Bank 2016, p. 13). Increased debt financing would increase the debt to equity ratio. This would mean that the government's capacity to leverage additional financing to cover future investments could decrease over time.

[91] In February 2018, Indonesia issued green Sukuk-bonds worth US$1.25 billion in compliance with Islamic Finance with some PLN projects to be on the priority list (Climate Bonds Initiative 2018).

Figure 5.9: Tariff and subsidy projections under RUPTL 2016–2025



Source: Author's calculations based on projected data in RUPTL 2016–2025 (PLN 2015) (see Appendices 5.7 and 5.8).

5.5 Conclusion

This chapter has analysed the financial governance system of the utility PLN and the historical trends of its subsidy and revenue streams. The financial conditions of PLN, largely driven by a political tariff and subsidy system, underpin much of the utility's investment decisions in the RE sector.

The core feature of PLN's financial governance is that the utility cannot charge cost-reflective tariffs to customers due to political constraints and, therefore, must rely on a subsidy as the major source of revenue. Seen from a historical perspective, this dependence on the subsidy has been the case since the existence of PLN in the 1960s and continues to be the case for much of the period under investigation (1990–2015). Electricity tariff and subsidy policies have been part of a public expenditure framework, which evolved from a closed ad hoc budget process under an authoritarian regime to a more democratic and political budget process after 1998. Since 2012, however, the government has undertaken significant steps in reducing energy subsidies, which included large electricity tariff increases for several consumer classes.

The evolving tariff and subsidy system has had three implications for the RE sector. First, the utility's budget is subject to a political process, which does not prioritise investment in RE. PLN's budget is determined by a political tariff and subsidy on an annual basis. Thus, PLN's decision to invest or buy power from IPPs is determined by a least-cost perspective to guard its financial prudence and to fulfil its mandated task to increase expansion of power supply to meet electrification targets. From the perspective of PLN, the regulatory mechanism of transferring the electricity subsidy and PSO investment margin to PLN has not provided sufficient incentives to the utility to take up renewables on a large scale.

Second, given that the subsidy is a significant part of PLN's revenues and that the utility is the single buyer of power generated by the private sector on the national grids, uncertainty about 'true' supply costs and the size of the subsidy raise doubts among investors about the utility's general commitment to take up more renewables. Perceptions on true costs of electricity supply and the size of the PSO subsidy differ between PLN, government, and IPPs, pointing to agency and asymmetric information problems. Benchmarking supply costs (BPP) are guided by 'least-cost' and 'cost-plus' perspectives between various agencies. As costs serve as the basis of PPA contracts between utilities and IPPs, the lack of reliable and transparent cost information prevents parties' full commitment to long-term contracts and thus might undermine regulatory instruments like FITs (see Chapter 3).

Third, despite receiving subsidies and a PSO margin, PLN faces a funding gap that constrains its ability to meet expansion targets. Therefore, the utility prioritises investment into coal and gas-powered generation, which have been cheaper than renewables in 1990–2015, the main period of investigation in this thesis.

The analysis suggests that Indonesia's RE policy context can be described in terms of a lack of incentives for PLN to credibly commit, adopt and invest in RE targets. Given the context of an imperfect subsidy and investment margin delivery mechanism, the behavioural implications for PLN are clear, as the utility is primarily concerned with cost and loss minimisation when purchasing electricity. This influences its choice of the fuel supply mix and thus impacts any electrification targets or any commitment to achieve RE targets.

As seen in Chapters 3 and 4, this suggests that the utility will be cautious in negotiating PPAs with IPPs, even with existing regulations mandating certain FIT rates. It can do so because it has considerable negotiating power as a single buyer in the market and can negotiate tariffs on a case-by-case basis, instead of automatically accepting the mandated prices.

From the perspective of an IPP wishing to sell renewable electricity, its selling price has to match PLN's BPP. Although the BPP has not been fully transparent for many years, industry players know that the utility's cost assessment is guided by the cheapest available option in each province where it wants to invest (excluding externality costs). Securing PPAs with PLN, therefore, depends on the utility's assessment of relevant supply costs on a case-by-case basis, subject to negotiations, despite existing GRs that mandate fixed purchasing prices of renewable power for PLN. Thus, IPPs selling to PLN face some uncertainty to secure PPAs, as they know that PLN's behaviour is determined by its need to minimise costs due its revenue constraints.

What are the policy options to increase investment in RE power generation? Given the current policy context of PLN acting as a VIM with limited financial resources and no binding RE targets, a clear funding mechanism is needed to achieve two goals: incentivise the utility to bridge the current cost gap between coal, gas and most renewables (especially geothermal), and reassure RE investors that PLN is creditworthy.

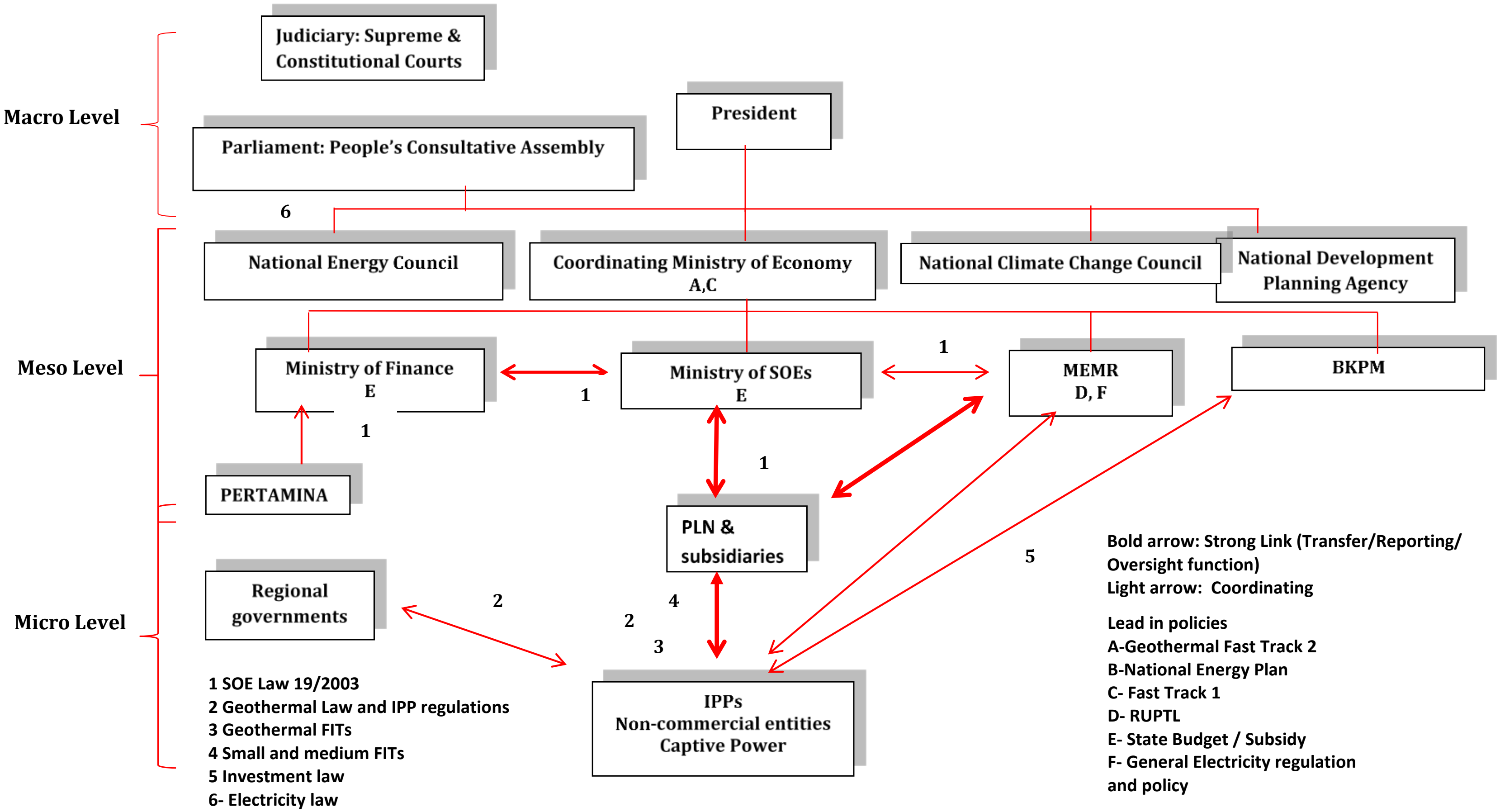
In terms of bridging the cost gap, currently the only way for PLN to buy renewables at mandated FITs—set higher than its average cost—is to pass the cost to the consumer via a tariff increase or to the government in the shape of increasing the electricity subsidy or increased debt financing. Given that there are significant constraints on the latter two options, PLN has to rely on tariff increases to consolidate its own financial base, which should increase the utility's willingness to take up more renewables. Significant tariff increases since 2014 suggest that the government has already recognised the need for PLN to substantially raise its investment capacity. Moreover, the falling costs of renewables such as solar and wind power will make it even more financially attractive to PLN to reduce its reliance on fossil fuels in the next few years. But even with declining costs of renewables, their high upfront costs, especially in the case of geothermal energy projects, will still require regulatory instruments to incentivise investment from PLN.

In terms of incentives, the government issued regulations to provide guarantees and mandate renewable FITs. It has launched a new guarantee program for projects in the 35 GW program. This program, regulated under MoF MR No. 130/PMK.08/2016, is designed to give loan guarantees to banks that provide loan financing to PLN or IPPs that partner with PLN. However, at the same time, the government has not managed yet to design FITs attractive enough for both PLN and IPPs to implement projects at a faster pace. On the contrary, the most recent FITs under MEMR MR No. 17/2017 suggest that RE producers have to offer selling prices that are below coal and gas, which is a major disincentive.

Overall, the findings of this chapter contribute to the wider literature on the interaction between governance structures in the electricity sector and the application of energy policy instruments. The Indonesian case study shows that the absence of an effective price pass-through mechanism undermines the effectiveness of an energy policy instrument such as a FIT. The hesitance of PLN to take up renewables on a larger scale is dictated by its incapacity to pass on the financing costs of FITs directly to consumers and the utility's dependence on a political subsidy system. The resulting financial constraints imposed on the utility undermine the effectiveness of Indonesian FITs.

All this suggests that the government has not yet found a balance between incentivising both PLN and renewable IPPs. Ultimately, this raises questions on whether, in the absence of any meaningful mandatory renewable targets, funding and subsidy mechanisms alone are effective to change the behaviour of major players in the power sector such as PLN. Mandatory quantitative RETs for PLN and wider macroeconomic tools like a carbon tax might be better suited to de-carbonise the power sector.

Appendix 5.1: Institutional framework of governing renewable energy investment



Appendix 5.2: PLN income statement (1990–2000) (million IDR)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Revenues											
Sale of electricity	3,139,323	4,062,661	4,794,366	5,922,138	2,979,351	8,109,711	9,418,269	10,877,278	13,766,222	15,670,552	22,139,883
Government's electricity subsidy											
Customer connection fees	64,097	69,775	77,980	96,112	48,954	143,276	170,034	200,754	206,869	222,223	241,698
Others	30,772	46,687	45,150	44,437	19,663	53,004	57,690	48,068	62,924	104,343	175,081
Total Revenues	**3,234,192**	**4,179,123**	**4,917,496**	**6,062,687**	**3,047,968**	**8,305,991**	**9,645,993**	**11,126,100**	**14,036,015**	**15,997,118**	**22,556,663**
Total revenues w/o subsidy											
Operating expenses											
Fuel and lubricants	1,530,708	1,828,628	2,131,993	2,783,017	1,193,343	2,969,995	3,361,080	4,338,836	9,408,965	9,691,813	10,375,827
Purchase electricity	21,260	22,661	19,716	46,859	30,679	77,096	183,236	325,162	1,885,963	5,082,703	9,395,365
Maintenance	233,005	339,455	498,366	561,693	352,142	808,935	911,267	965,397	924,840	1,497,830	1,610,254
Personnel	278,643	307,715	427,384	504,368	281,792	758,291	886,229	1,068,055	1,018,858	1,335,616	1,802,392
Depreciation	558,977	629,719	712,384	909,049	519,240	1,566,472	1,886,972	2,250,725	3,074,149	3,224,331	3,229,593
Others	112,048	161,877	202,613	265,126	159,572	356,355	413,726	501,578	495,998	670,384	802,390
Total operating expenses	**2,734,641**	**3,290,055**	**3,992,456**	**5,070,112**	**2,536,768**	**6,537,145**	**7,642,510**	**9,449,753**	**16,808,773**	**21,502,678**	**27,215,821**
Income from Operations (Profit&Loss)	499,551	889,068	925,040	992,575	511,200	1,768,846	2,003,483	1,676,347	- 2,772,758	- 5,505,560	- 4,659,158
Income w/o subsidy											

Source: PLN Annual Statistics (1990–2015).

Appendix 5.3: PLN income statement (2001–2015) (million IDR)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Revenues															
Sale of electricity	28,275,983	39,018,462	49,809,637	58,232,002	63,246,221	70,735,151	76,286,195	84,249,726	90,172,100	102,973,531	112,844,853	126,721,647	153,485,606	186,634,484	209,844,541
Government's electricity subsidy	6,735,210	4,739,074	4,096,633	3,469,920	12,510,960	32,909,148	36,604,751	78,577,390	53,719,818	58,108,418	93,177,740	103,331,285	101,207,859	99,303,250	56,552,532
Customer connection fees	265,858	302,308	342,257	387,084	439,917	479,991	535,269	589,622	651,716	760,837	1,008,730	1,306,463	6,027,799	5,623,913	6,141,335
Others	82,907	123,510	182,251	184,057	346,226	602,246	616,472	791,772	678,510	532,508	986,500	1,297,061	1,125,778	1,159,544	1,361,114
Total Revenues	**35,359,958**	**44,183,353**	**54,430,778**	**62,273,063**	**76,543,324**	**104,726,536**	**114,042,687**	**164,208,510**	**145,222,144**	**162,375,294**	**208,017,823**	**232,656,456**	**261,847,042**	**292,721,191**	**273,899,522**
Total revenues w/o subsidy	28,624,748	39,444,280	50,334,145	58,803,143	64,032,364	71,817,388	77,437,936	85,631,120	91,502,326	104,266,876	114,840,083	129,325,171	160,639,183	193,417,941	217,346,990
Operating expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel and lubricants	14,007,296	17,957,262	21,477,867	24,491,052	37,355,450	63,401,080	65,559,977	107,782,838	85,498,930	93,898,743	131,157,604	136,535,495	147,633,751	153,136,934	120,587,310
Purchase electricity	8,717,141	11,168,843	10,833,999	11,970,811	13,598,167	14,845,421	16,946,723	20,742,905	3,660,090	4,120,795	7,032,572	9,903,607	2,393,790	53,517,212	59,251,861
Maintenance	2,630,360	3,588,828	4,827,606	5,202,146	6,511,004	6,629,065	7,269,142	7,619,854	9,940,274	11,740,829	13,592,563	-	8,114,145	7,866,347	-
Personnel	2,086,330	2,583,290	3,827,686	5,619,384	5,508,067	6,719,746	7,064,316	8,344,224	9,758,314	12,954,418	13,197,075	17,567,375	19,839,465	16,611,461	17,593,261
Depreciation	3,404,114	15,626,763	12,745,047	9,547,555	9,722,315	10,150,985	10,716,237	11,372,849	13,921,222	14,691,919	16,254,552	14,400,976	15,555,063	16,645,797	20,321,137
Others	1,094,147	1,420,607	2,165,000	2,879,819	3,328,598	3,481,853	3,949,560	4,735,081	4,035,539	4,286,003	4,405,234	19,499,221	21,893,665	19,911,211	21,418,640
Total operating expenses	**31,939,387**	**52,345,592**	**55,877,205**	**59,710,767**	**76,023,601**	**105,228,150**	**111,505,955**	**160,597,751**	**126,814,369**	**141,692,707**	**185,639,600**	**5,208,776**	**5,481,268**	**5,488,617**	**7,090,077**
Income from Operations (Profit&Loss)	**3,420,571**	**- 8,162,238**	**- 1,446,427**	**2,562,296**	**519,723**	**- 501,614**	**2,536,732**	**3,610,759**	**18,407,775**	**20,682,587**	**22,378,223**	**29,541,006**	**40,935,895**	**19,543,612**	**27,637,236**
Income w/o subsidy	- 3,314,639	- 12,901,312	- 5,543,060	- 907,624	- 11,991,237	- 33,410,762	- 34,068,019	- 74,966,631	- 35,312,043	- 37,425,831	- 70,799,517	- 73,790,279	- 60,271,964	- 79,759,638	- 28,915,296

Source: PLN Annual Statistics (1990–2015).

Appendix 5.4: Energy subsidies in the state budget (2001–2015)

State Budget	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
State Revenues and Grants	301,078	298,528	341,396	403,367	495,226	637,987	707,806	981,610	848,763	995,272	1,210,599	1,338,110	1,438,891	1,550,491	1,508,020	1,786,225	2,050,817	2,299,852	2,596,677
State Expenditure	341,543	318,632	376,505	427,176	509,632	667,129	757,650	985,731	937,382	1,042,117	1,294,999	1,491,410	1,650,564	1,777,183	1,806,515	2,082,949	2,327,250	2,547,344	2,807,366
- Central Government	260,488	223,976	256,191	297,464	361,155	440,032	504,623	693,356	628,812	697,406	883,722	1,010,558	1,137,163	1,203,577	1,183,304	1,306,696	1,443,750	1,572,325	1,719,786
Budget Surplus/Deficit	(40,465)	(20,105)	(35,109)	(23,809)	(14,407)	(29,142)	(49,844)	(4,122)	(88,619)	(46,846)	(84,400)	(153,301)	(211,673)	(226,692)	(298,495)	(296,724)	(276,433)	(247,491)	(210,689)
Deficit ratio	(2.8)	(1.1)	(1.7)	(1.0)	(0.5)	(0.9)	(1.3)	(0.1)	(1.6)	(0.7)	(1.1)	(1.9)	(2.3)	(2.2)	(2.55)	(2.3)	(2.0)	(1.6)	(1.2)
Energy Subsidies	68,361	31,162	30,038	71,341	104,449	94,605	116,866	223,013	94,586	139,953	255,608	306,479	309,980	341,810	119,091	94,355	98,254	95,271	98,102
- Fuel	61,626	26,423	25,941	69,025	95,599	64,212	83,792	139,107	45,039	82,351	165,161	211,896	210,000	239,994	60,759	43,687	56,214	51,108	51,555
- Electricity	6,735	4,739	4,097	2,317	8,851	30,393	33,074	83,907	49,546	57,602	90,447	94,583	99,980	101,816	58,332	50,668	42,040	44,163	46,548
Macroecomomic Assumptions																			
a. Nominal Gross Domestic Product (GDP)	1,449,398	1,821,833	2,013,675	2,295,826	2,784,960	3,338,196	3,957,404	4,954,029	5,613,400	6,422,918	7,427,100	8,248,588	9,084,000	10,094,929	11,700,808	12,634,694	14,099,121	15,555,701	17,245,462
b. Economic (Real GDP) Growth (%)	3.4	4.3	4.5	4.8	5.7	5.5	6.3	6.1	4.5	6.1	6.5	6.3	5.8	5.1	6	5.3	6.2	6.6	7.3
c. Inflation (%)	12.6	10.0	5.1	7.0	17.1	6.6	6.6	11.1	2.8	7.0	3.8	4.3	8.4	8.4	5	4.0	4.0	3.5	3.5
d. Exchange Rate (Rp/US$)	10,260	9,311	8,577	8,900	9,705	9,063	9,419	9,691	10,408	9,078	8,779	9,384	10,451	11,878	12,500	13,500	13,100	13,000	12,900
e. Interest rate of SBI (average %)	16.4	15.2	10.2	7.6	9.1	11.7	8.0	9.3	6.6	6.6	4.8	3.2	4.5	5.8	6	5.5	5.0	4.5	4.5
f. Crude-Oil Price (US$/Barrel)		23.5	28.8	34.0	51.8	63.8	78.0	97.0	61.5	79.4	112	112.7	106	97	60	35	70	70	75
g. Oil Production (thousand barrels per day)		1,260.0	1,092.0	1,072.0	999	959	909	931	950	954	899	861	825	794	825	810	750	700	600
h. Gas Production (TBOEPD)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		1,213	1,224	1,221	1,115	1,150	1,200	1,200

Notes: * revised ** Proposed

Source: MoF.

Appendix 5.5: PLN balance sheet (1990–2000) (million IDR)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Current assets	1,547,978	1,880,974	22,228,495	2,355,161	2,381,402	2,430,657	3,677,332	3,017,423	6,985,014	6,456,711	8,744,627	11,381,754
Non-current (fixed) assets	12,364,474	13,941,725	14,751,704	22,390,588	19,977,601	28,773,451	33,248,288	48,165,604	60,085,451	63,575,641	67,461,767	71,199,099
- Accumlated depreciation	- 2,805,574	- 3,428,474	- 4,123,883	- 4,986,800	- 520,240	- 1,562,841	- 3,409,213	- 5,636,111	- 8,690,483	- 11,756,221	- 14,820,678	- 18,150,769
Net fixed assets	9,558,900	10,513,251	10,627,821	17,403,787	19,457,361	27,210,610	29,839,075	42,529,493	51,394,968	51,819,420	52,641,089	53,048,330
Liabilities	5,606,235	6,346,053	10,401,080	12,284,712	14,242,383	18,354,819	20,894,068	27,388,908	48,093,107	55,636,307	56,135,505	57,185,571
Long term	4,454,780	5,169,340	8,677,917	10,572,299	11,117,091	14,534,647	17,608,536	22,538,980	30,259,393	25,914,052	34,251,748	32,915,408
Short term	1,151,455	1,176,713	1,723,163	1,712,413	3,125,292	3,820,172	3,285,532	4,849,928	17,833,714	29,722,255	21,883,757	24,270,163
Equity	7,571,278	10,319,916	13,066,271	16,662,052	19,583,174	23,505,602	29,231,520	30,271,943	23,395,074	14,506,539	18,625,103	18,198,001
Deferred revenues	880,576	924,247	1,076,450	1,429,656	1,736,089	2,091,478	2,458,208	2,847,458	2,972,169	3,076,638	3,234,451	3,502,134
Total assets, equity and liabilities	14,058,089	17,590,216	24,543,802	30,376,420	35,561,646	43,951,899	52,583,796	60,508,309	74,460,350	73,219,484	77,995,059	78,885,706

Financial health indicators	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Operating ratio		78.7	81.2	83.6	83.2	78.7	79.2	84.9	119.8	134.0	120.7	111.6
ROR on net average fixed assets		8.8	7.7	6.4	2.7	7.6	7.0	4.6	-6.8	-10.7	-8.9	-1.6
Self financing ratio		24.2	43.7	21.6	33.9	27.6	30.7	32.7	56.6	7.8	46.9	101.7
Debt service coverage (times)		3.1	3.0	2.5	7.7	5.8	2.4	1.0	0.1	0.5	2.5	1.0
Debt to debt+equity ratio	39.9	36.1	42.4	40.4	40.0	41.8	39.7	45.3	64.6	76.0	72.0	72.5

Source: PLN Annual Statistics (1990–2015).

Appendix 5.6: PLN balance sheet (2000–2015) (million IDR)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Current assets	11,381,754	12,893,307	12,297,734	12,679,406	17,665,189	28,821,273	43,212,986	30,926,930	36,734,390	44,773,286	58,252,342	68,639,956	84,837,180	85,423,738	79,344,793
Non-current (fixed) assets	71,199,099	201,318,267	207,491,683	217,604,612	224,680,444	257,695,815	266,884,239	327,775,239	350,669,602	365,206,962	435,468,124	509,013,383	475,832,252	515,208,872	1,029,246,687
- Accumlated depreciation	- 18,150,769	- 15,700,329	- 28,421,314	- 37,820,831	- 47,289,093	- 57,312,559	- 67,982,406	- 91,492,548	- 104,645,340	- 117,645,247	- 132,978,177	- 150,988,899	- 145,165,591	- 169,708,586	- 18,579,384
Net fixed assets	53,048,330	185,617,938	179,070,369	179,783,781	177,391,351	200,383,256	198,901,833	236,282,691	246,024,262	247,561,715	302,489,947	358,024,484	330,666,661	345,500,286	1,010,667,303
Liabilities	57,185,571	57,815,415	53,351,673	64,300,185	75,230,994	101,827,495	130,150,819	207,245,893	230,043,111	253,860,518	307,181,861	370,877,400	349,427,363	352,347,652	143,217,441
Long term	32,915,408	42,964,715	37,189,092	47,108,562	49,274,802	74,129,090	89,874,565	159,542,013	182,042,100	198,463,967	243,631,428	296,274,497	290,226,868	266,818,225	26,213,010
Short term	24,270,163	14,850,700	16,162,581	17,191,623	25,956,192	27,698,405	40,276,254	47,703,880	48,001,011	55,396,551	63,550,433	74,602,903	59,200,495	85,529,427	117,004,431
Equity	18,198,001	152,084,320	149,742,597	142,348,843	139,753,679	139,837,946	136,412,740	115,035,690	133,465,034	142,113,775	146,012,836	150,599,670	174,225,129	187,173,537	848,219,071
Deferred revenues	3,502,134	3,998,868	4,251,360	5,144,568	5,858,062	6,252,377	6,916,376	7,556,638	8,297,478	10,126,136	14,587,906	19,228,694	990,913	1,306,976	1,533,703
Total assets, equity and liabilities	78,885,706	213,898,603	207,345,630	211,793,596	220,842,735	247,917,818	273,479,935	329,838,221	371,805,623	406,100,429	467,782,603	540,705,764	524,643,405	540,828,165	992,970,215

Financial health indicators	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Operating ratio	111.6	118.5	102.7	95.9	99.3	100.5	97.8	97.8	87.3	87.3	89.2	87.3	89.9	90.6	89.9
ROR on net average fixed assets	-1.6	-1.7	-0.2	0.4	0.3	0.1	0.3	0.4	6.0	4.2	2.0	1.0	-7.9	1.6	2.0
Self financing ratio	101.7	86.2	71.1	74.8	52.8	60.9	98.5	157.4	30.1	51.4	34.4	40.3	91.7	79.0	161.2
Debt service coverage (times)	1.0	2.0	2.8	1.0	3.0	4.5	3.4	6.4	1.9	2.3	1.8	1.7	2.1	1.6	1.5
Debt to debt+equity ratio	72.5	27.0	25.7	30.4	34.1	41.1	47.6	62.8	61.9	62.5	65.7	68.6	66.6	65.1	14.4

Source: PLN Annual Statistics (1990–2015).

Appendix 5.7: Income statement projections: Business-as-usual scenario

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenues										
Sale of electricity	295,015,984	385,220,947	472,905,320	523,930,040	559,486,455	598,689,682	645,868,395	698,915,716	750,637,621	788,852,532
Government's electricity subsidy	79,506,004	103,815,996	127,446,695	141,197,718	150,780,075	161,345,238	174,059,773	188,355,881	202,294,794	212,593,608
Customer connection fees	8,633,972	11,273,922	13,840,103	15,333,398	16,373,996	17,521,323	18,902,060	20,454,550	21,968,249	23,086,651
Others	1,913,561	2,498,657	3,067,404	3,398,366	3,628,995	3,883,279	4,189,294	4,533,375	4,868,858	5,116,732
Total Revenues	385,069,522	502,809,522	617,259,522	683,859,522	730,269,522	781,439,522	843,019,522	912,259,522	979,769,522	1,029,649,522
Total revenues w/o subsidy		-	-	-	-	-	-	-	-	
Operating expenses	-	-	-	-	-	-	-	-	-	-
Fuel and lubricants	138,589,286	159,278,701	183,056,753	210,384,530	241,791,958	277,888,069	319,372,817	367,050,650	421,846,108	484,821,751
Lease	68,097,324	78,263,289	89,946,888	103,374,683	118,807,057	136,543,267	156,927,240	180,354,252	207,278,585	238,222,339
Purchase electricity	-	-	-	-	-	-	-	-	-	-
Maintenance	20,219,685	23,238,198	26,707,331	30,694,357	35,276,589	40,542,884	46,595,362	53,551,389	61,545,852	70,733,775
Personnel	23,354,795	26,841,334	30,848,365	35,453,588	40,746,307	46,829,152	53,820,081	61,854,656	71,088,679	81,701,211
Depreciation	24,616,139	28,290,980	32,514,422	37,368,364	42,946,931	49,358,299	56,726,793	65,195,299	74,928,033	86,113,726
Others	8,148,525	9,364,984	10,763,044	12,369,813	14,216,451	16,338,766	18,777,912	21,581,188	24,802,953	28,505,682
Total operating expenses	283,025,754	325,277,486	373,836,802	429,645,336	493,785,293	567,500,436	652,220,205	749,587,434	861,490,210	990,098,483
Income from Operations (Profit&Loss)	378,532,377	495,167,012	607,809,769	667,050,749	708,766,844	754,223,701	811,080,135	859,913,930	923,892,317	969,938,755
Income w/o subsidy	299,026,373	391,351,016	480,363,074	525,853,031	557,986,769	592,878,463	637,020,363	671,558,049	721,597,524	757,345,147
Average Basic Tariff Rates (TDL in IDR)	1,360	1,579	1,765	1,794	1,776	1,761	1,765	1,774	1,766	1,726
Projected electricity sales in GWh	217,000	244,000	268,000	292,000	315,000	340,000	366,000	394,000	425,000	457,000
Sale of electricity	100	131	160	178	190	203	219	237	254	267
Government's electricity subsidy	100	131	160	178	190	203	219	237	254	267
Average Basic tariff Rates (TDL)	100	116	130	132	131	130	130	130	130	127
Projected electricity sales in GWh	100	112	124	135	145	157	169	182	196	211

Source: Author's calculations based on RUPTL 2016–2025.

Appendix 5.8: Income statement projections scenario with phase-out of subsidy

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenues										
Sale of electricity	295,015,984	385,220,947	506,152,808	581,280,594	620,729,094	664,223,594	716,566,594	775,420,594	832,804,094	875,202,094
Government's electricity subsidy	79,506,004	103,815,996	92,588,928	82,063,143	73,026,952	39,071,976	25,290,586	-	-	-
Customer connection fees	8,633,972	11,273,922	13,840,103	15,333,398	16,373,996	17,521,323	18,902,060	20,454,550	21,968,249	23,086,651
Others	1,913,561	2,498,657	3,067,404	3,398,366	3,628,995	3,883,279	4,189,294	4,533,375	4,868,858	5,116,732
Total Revenues	385,069,522	502,809,522	617,259,522	683,859,522	730,269,522	781,439,522	843,019,522	912,259,522	979,769,522	1,029,649,522
Total revenues w/o subsidy	-	-	-	-	-	-	-	-	-	-
Operating expenses	-	-	-	-	-	-	-	-	-	-
Fuel and lubricants	138,589,286	159,278,701	183,056,753	210,384,530	241,791,958	277,888,069	319,372,817	367,050,650	421,846,108	484,821,751
Lease	68,097,324	78,263,289	89,946,888	103,374,683	118,807,057	136,543,267	156,927,240	180,354,252	207,278,585	238,222,339
Purchase electricity	-	-	-	-	-	-	-	-	-	-
Maintenance	20,219,685	23,238,198	26,707,331	30,694,357	35,276,589	40,542,884	46,595,362	53,551,389	61,545,852	70,733,775
Personnel	23,354,795	26,841,334	30,848,365	35,453,588	40,746,307	46,829,152	53,820,081	61,854,656	71,088,679	81,701,211
Depreciation	24,616,139	28,290,980	32,514,422	37,368,364	42,946,931	49,358,299	56,726,793	65,195,299	74,928,033	86,113,726
Others	8,148,525	9,364,984	10,763,044	12,369,813	14,216,451	16,338,766	18,777,912	21,581,188	24,802,953	28,505,682
Total operating expenses	283,025,754	325,277,486	373,836,802	429,645,336	493,785,293	567,500,436	652,220,205	749,587,434	861,490,210	990,098,483
Income from Operations (Profit&Loss)	378,532,377	495,167,012	607,809,769	667,050,749	708,766,844	754,223,701	811,080,135	859,913,930	923,892,317	969,938,755
Income w/o subsidy	299,026,373	391,351,016	480,363,074	525,853,031	557,986,769	592,878,463	637,020,363	671,558,049	721,597,524	757,345,147
Average Basic Tariff Rates (TDL, in IDR))	1360	1579	1889	1991	1971	1954	1958	1968	1960	1915
Projected electricity sales in GWh	217,000	244,000	268,000	292,000	315,000	340,000	366,000	394,000	425,000	457,000
Sale of electricity	100	131	172	197	210	225	243	263	282	297
Government's electricity subsidy	100	131	116	103	92	49	32	0	0	0
Average Basic tariff Rates (TDL)	100	116	139	146	145	144	144	145	144	141
Projected electricity sales in GWh	100	112	124	135	145	157	169	182	196	211

Source: Author's calculations based on RUPTL 2016–2025.

Chapter 6: Costs and Risks in the Indonesian Electricity Sector: Implications for Renewable Energy Investment

Abstract

Given the global decline of RE costs in recent years and the government's commitment to achieve lower CO_2 emissions targets, PLN will have to reassess its investment strategy and include more renewables in its future energy mix. However, despite the decline in the costs of renewables, coal-fired generation still plays an important role in the utility's expansion plans. This implies that we need to adopt a broader view when assessing the utility's investment choice, one that not only looks at costs but includes risks associated with investing in specific technologies.

This chapter provides a framework to assess generation investments both in terms of their cost and the cost risk that they pose to PLN. Generally, costs are assessed by looking at the LCOE. Cost risk is then quantified by attaching risk coefficients—defined as standard deviations of past cost streams—to LCOEs to arrive at a measure of 'cost risk' or 'cost uncertainty' associated with investing in particular generation technologies. The utility's investment risk can then be viewed as a *portfolio risk*, which is determined both by the cost risk associated with the individual generation technology, and by its correlation with the electricity generation portfolio cost risk.

From a LCOE perspective, as of 2016, most renewables were already competitive with coal- and gas-fired generation. Prices of most renewables, notably geothermal, hydropower and solar PV, are now competing with coal and gas in the 3–8 cents/kWh price range across a range of discount rates. From a cost risk perspective, the lowest levels of risk are associated with small-scale renewables such as wind, solar and small hydropower. This can be mainly explained by the absence of fuel price risks and the low standard deviations associated with capital and construction costs. The highest levels of risk are associated with those technologies that are tied to fuel price risks such as coal and that have large construction/capital risks, including renewables like large hydropower and geothermal.

6.1 Introduction

The previous chapter showed that PLN's financial constraints are a major impediment to a quicker uptake of RE in the electricity sector. In the absence of credible RE targets for PLN, the utility did not have enough incentives to invest in more renewables. Instead, it has favoured investment in coal-fired power supply, which historically has been cheaper than most renewables in the observed period (1990–2015).

However, despite the global decline of RE costs in recent years and the government's commitment to achieve lower CO2 emissions targets, coal-fired electricity generation still plays an important role in the utility's investment strategy. This necessitates an approach that assesses the wider risks and uncertainties associated with both fossil fuels and renewable generation technologies.

The risk of coal-fired generation technology, for instance, includes price fluctuations and the unaccounted economic costs of released carbon emissions. Renewable technologies are generally considered to have lower risk profiles than conventional technologies, as they are insulated from swings in fossil fuel prices. But renewables are also exposed to technology-specific and regulatory risks, which might render them still too costly for PLN, as in the case of geothermal technology with its high upfront costs or the risk from intermittency associated with solar and wind power. In short, assessing risk of investing in generation technologies is a multi-dimensional exercise with some risks quantifiable and others not.

The main objective of this chapter is to provide a framework to assess generation investments both in terms of their cost and the cost risk that they pose to PLN. Cost risk is calculated by first estimating the LCOE and then attaching risk coefficients—defined as standard deviations of past cost streams—to those LCOEs to arrive at a measure of 'cost risk' or 'cost uncertainty' associated with specific generation technologies. By applying a quantitative cost and cost risk analysis this chapter fills a gap in the literature on risk assessment in the Indonesian power sector.

Cost risk defined in this way is then used to apply MVP theory to model the long-term supply scenarios of PLN in Chapter 7. MVP theory provides a framework to assess the relative importance of individual generation technologies in a given mix or portfolio of generation technologies. The utility's investment risk can then be viewed as a *portfolio risk* which is determined both by the cost risk associated with the individual generation technology, and by its correlation with the electricity generation portfolio cost risk.

Section 6.2 discusses the concepts of LCOE, cost risk and portfolio risk as part of a broader MVP theory. Section 6.3 estimates LCOE in Indonesia's power sector. Section 6.4 estimates cost risks for individual generation technologies in the Indonesian electricity sector. A final section concludes and provides an outlook for the subsequent chapter on modelling portfolio risks in PLN's long-term supply mix scenario.

6.2 Generation costs and cost risk in the Indonesian electricity sector

6.2.1 Risks in PLN's planning document

Assessing the risk of investing in the power sector is a multi-dimensional exercise, as risks can be related to technological, regulatory, financial, economic or social factors. The utility PLN provides a broad assessment of risks in its annual planning document, RUPTL. PLN maps the likelihood of the event actually occurring—the risk probability—against the severity of the impact if the event actually occurs (see Table 6.1). According to the utility's perception, the highest risk probability is attached to the delay of projects implemented by both PLN and IPPs (PLN 2016b, p. 210).

Similarly, financing and liquidity risks are described as very high probability risks, with a high significance attached in terms of potential impacts. Financial risk is described in a broad sense as the risk associated with the uncertainty of the source of financing. Interestingly, liquidity risk describes not only liquidity as cash and asset liquidity, but specifically refers to the risk of the smooth disbursement of the subsidy to PLN (PLN 2016b, p. 209).

Environmental and social risks attached to the implementation of projects are viewed as posing a medium risk, with medium impact. The remaining events are categorised as relatively low- or medium-risk and impact scenarios (PLN 2016b, pp. 92–93).

Table 6.1: PLN risk assessment

Risk factors	Risk probability (likelihood of occurring)	Significance of impact	Extreme high-risk issue
Delay of IPP projects	Very high risk	Very significant	yes
Delay of PLN projects	Very high risk	Very significant	yes
Liquidity financing	Very high risk	Very significant	yes
Environmental/social	Medium	Medium	
Production/operational	Medium	Medium	
Regulatory	Medium	Medium	
Supply and price of primary energy	Very high	Very significant	yes
Electricity demand forecast	Medium	Medium	
Too high reserve margin	Very small	Medium	
Natural disaster	Small	Small	

Source: PLN (2015, pp. 209–213).

PLN's risk assessment is a broad and purely qualitative exercise that does not include a quantitative evaluation of specific risks associated with individual generation technologies. Arguably, high-risk factors identified by PLN—delay of IPP and PLN projects, liquidity and financing—are related to risks associated with costs of investing in specific technologies. As highlighted in the previous chapters, electricity supply costs vary across technologies, with different factors influencing cost streams. For example, variations in world prices of coal affect the cost streams of coal-based generation costs. Renewables are not subject to these fuel price fluctuations but might face higher costs due to higher upfront capital costs. Understanding cost structures of individual technologies and the wider economic factors that influence the variations in those cost streams—cost risk—is vital to understanding the investment behaviour of public utilities.

6.2.2 Mean variance portfolio theory: A framework for determining portfolio and cost risk in the electricity sector

MVP theory is a framework to assess the trade-offs between costs and risks associated with individual generation technologies (Awerbuch & Yang 2008; Dornan & Jotzo 2015). MVP theory has its origins in financial theory where it was developed to assess the impact of an individual financial security on the return and risk of a whole portfolio (Markowitz 1952). Stock markets are risky, because there is a spread of possible outcomes. This spread is normally measured by the standard deviation or variance (Brealey & Myers 2000, p. 187). Risk is then seen in terms of how far the actual return of an individual security deviates from its expected return. If the returns of an individual security are highly correlated with those of the whole portfolio of securities, it will increase the risk of the portfolio and vice versa. Investors can mitigate risk if they hold a balanced and well-diversified portfolio (Brealey & Myers 2000, p. 187–212). Specifically:

$$E(r_p) = X_1 E(r_1) + X_2 E(r_2) \qquad (1)$$

Where $E(r_p)$ is the expected portfolio return, $E(r_i)$ is the expected (mean) return to each security, X_1 and X_2 are the share of each security (technology) in the portfolio. Portfolio risk σ_p is obtained by using:

$$\sigma_p = \sqrt{X_1^{\;2}\sigma_1^2 + X_2^2\sigma_2^2 + 2X_1X_2\rho_{12}\sigma_1\sigma_2} \qquad (2)$$

Where σ_p is the portfolio risk, ρ_{12} is the correlation coefficient between the two return streams, σ_1 and σ_2 are the standard deviations of return (Brealey & Myers 2000, pp. 187–212).

The same principles can be applied to the energy sector, with generation costs replacing returns as the main data. Historical trends of generation costs for individual technologies are constructed and used to measure the variance of these trends. The variance of the individual technology is then correlated to the variance of the whole generation mix (portfolio). If the cost stream of an individual technology has a high correlation with the overall generation mix, then it does not add to the utility's risk, because it moves with the costs of the whole electricity grid (Dornan & Jotzo 2012, p. 15).

Within the context of the fossil fuel–dominated grid of Indonesia, portfolio analysis can be used to assess the risk mitigation benefits of renewable generation technologies. In theory, the risk mitigation potential of renewables is high, because they are not exposed to fuel price risks and thus should decrease PLN's financial risk exposure. MVP analysis can provide a quantitative framework to assess the extent to which a diversification of a portfolio or energy supply mix can benefit the energy system in terms of finding the optimal balance that minimises costs and risks (De Paz & Silvosa 2012).

Traditionally, MVP is mostly used to assess financial risks, defined as variations in investment returns in the power sector (Ioannou, Angus & Brennan 2017). Within the Indonesian context, I focus on the interaction between cost risk—the variation of cost streams of individual generation technologies—and portfolio risk.

By the overall 'risk' in the Indonesian electricity sector, I mean the 'portfolio risk' associated with a PLN's energy supply mix. Portfolio risk is determined by the interaction of two variables. First, average LCOE of an individual generation technology represents the standalone cost of producing one unit of electricity. Second, 'cost risk' or 'cost uncertainty' describes the volatility or variations of past cost streams associated with individual generation technologies. Given that PLN dominates the grid as the single buyer, it can be argued that the utility's portfolio risk constitutes a sector-wide risk. The remainder of the chapter will clarify the concepts and present estimates for LCOEs and cost risks of generation technologies in the Indonesian power sector.

6.2.3 Levelised generation costs in the Indonesian power sector

The LCOE is a standard method for calculating and comparing different cost streams of electricity generation technologies. It represents the supply cost of electricity associated with a specific generation technology and the minimum price at which a utility or any energy producer would be willing to sell the produced electricity, if it wants to break even. The LCOE can be seen as the long-run marginal cost of electricity, because it measures the cost of producing one extra unit of electricity of a newly constructed generation plant.

The LCOE is based on a discounted cashflow analysis and shows the costs of a power plant over its lifetime and is, therefore, expressed in net present value terms. As seen in equation (2) below, the LCOE is calculated by adding the investment (or overnight capital) cost of the power plant, fixed and variable operation and maintenance costs, and fuel costs.

$$\text{LCOE} = \frac{(I_t * CRF) + FOM}{8760 * CF} + \text{F* heat rate} + \text{VOM} \quad (2)$$

where

I_t = Investment/Capital expenditures in year t (in USD/kW)

FOM = Fixed Operation and Maintenance Costs (measured in US$/kw)

VOM = Variable Operation and Maintenance Costs (in USD/MWh or kWh)

F = Fuel costs (in USD/MWh or USD/kWh)): Fuel price * (net plant output/thermal efficiency/100) * hours in year * (capacity factor/100)

Heat rate = energy content of fuel used per kWh generated

Thermal efficiency = Btu content of 1 kWh/heat rate

CF = capacity factor of power plant

CRF = capital recovery factor = {i(1 + i)^n} / {[(1 + i)^n]-1}[92]

with

i = discount rate

n = Economic life of power plant

Source: National Renewable Energy Laboratory (2016); IRENA (2012a).

[92] A capital recovery factor is the ratio of a constant annuity to the present value of receiving that annuity for a given length of time.

Capital costs are discounted by the capital recovery factor using a discount factor i.[93] The choice of the discount factor is important, as it significantly influences the cost of the generation technology in question. It is driven by the prevailing market interest rates in the economy, which in turn mirror a host of policy-related factors that determine risk perception among investors (IRENA 2012, p. 3).

Some caveats need to be mentioned regarding the use of the LCOE. It is a relatively broad indicator, which does not fully account for all costs involved in producing electricity. LCOEs represent busbar[94] costs, which exclude all transmission and distribution costs. They also do not include financing costs, degradation costs and future replacement costs. Moreover, it leaves out several factors that might affect OM costs, including the age of power plants and different operating times. Finally, the LCOE formula used as in equation (2) only makes I_t, capital investment, sensitive to interest rate changes and assumptions.

Given the lack of detailed, publicly available historical data on cost and performance of power plants, LCOEs serve as a good base for policymakers to assess the relative cost performance between renewable and non-renewable generation technologies (IRENA 2012, p. 1).

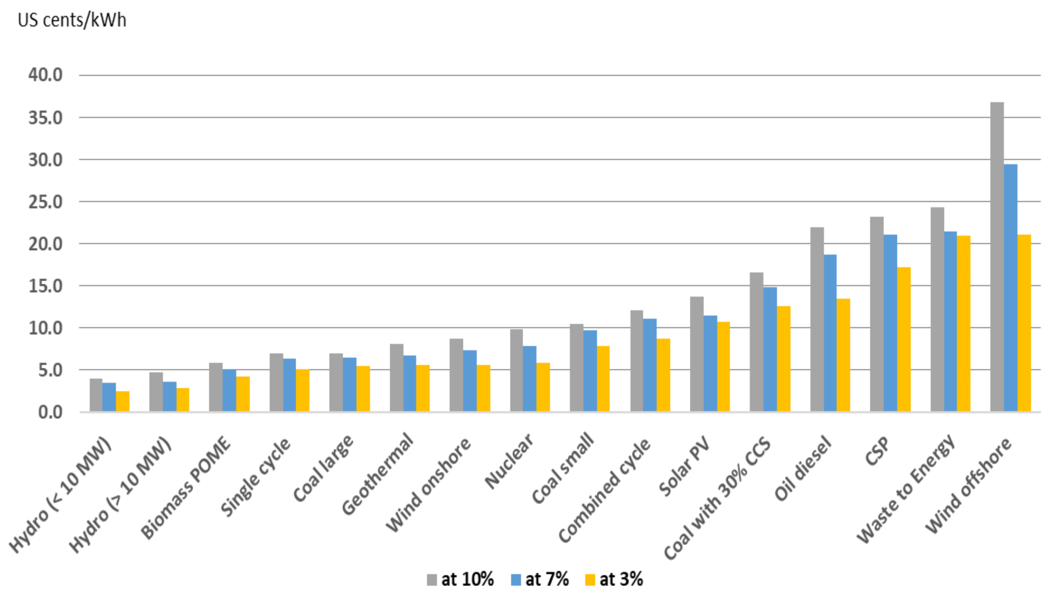
Using the above equation (2) and cost assumptions as explained further below (see Table 6.4), LCOEs for current prices in 2016 were calculated (see Figure 6.1 and Table 6.2), as were future prices in 2025 and 2035 (see Table 6.3). The reason for the choice of these specific years is that PLN's latest projection covers the period from 2016–2025 under its RUPTL forecast (PLN 2016b). Additionally, the projections for 2035 are shown to illustrate potential longer-term LCOE changes, using projected growth rates from various international studies, notably from the IREA (2016), and cost projections made by the Electricity Power Research Institute (EPRI) (2015) and the Australian Power Generation Technology Report (Electric Power Research Institute 2015) (see Table A3 in Appendix 6.1).

---

[93] The discount factor is also frequently referred to as the weighted average cost of capital. The discount factor is especially sensitive to the share of debt and equity finance.

[94] The power plant bus or busbar is that point beyond the generator but prior to voltage transformation point in the plant switchyard.

Figure 6.1: Levelised cost of electricity in the Indonesian power sector (2016)



Source: Author's calculations based on data in Table 6.2.

The results indicate that the cost of most renewables have already come down in recent years. As of 2016, they are already competitive with large coal and single gas cycle plants and are significantly cheaper than diesel (oil) fired generation. Prices of some renewables, notably geothermal,[95] hydropower and biomass, are competing in the 3–8 cents/kWh price range across all discount rates.

However, as previously mentioned, these LCOE estimates represent busbar costs, and are largely driven by assumptions about the interest rate environment and capital, maintenance, and fuel costs associated with investing in power plants. These will be discussed in the following sections.

[95] A comprehensive survey by the World Bank (2015, p. 59) of levelised tariffs of 23 existing Indonesian geothermal project sites also found that costs were in line or below costs of coal-fired power projects, ranging between 6.5–9.5 cents/kWh.

Table 6.2: Levelised cost of electricity (2016) (in USD 2015)

Type	Levelised generation costs at 10%				Levelised generation costs at 7%				Levelised generation costs at 3%			
	Capital	Fuel	OM	Total	Capital	Fuel	OM	Total	Capital	Fuel	OM	Total
Single cycle	2.6	3.6	0.7	7.0	2.0	3.6	0.7	6.3	1.3	3.6	0.7	5.6
Combined cycle	2.7	9.0	0.4	12.1	2.1	9.0	0.4	11.5	1.3	9.0	0.4	10.7
Coal large	3.5	4.3	0.7	8.4	2.7	4.3	0.7	7.6	1.7	4.3	0.7	6.6
Coal small	3.6	5.6	1.4	10.5	2.7	5.6	1.4	9.7	1.7	5.6	1.4	8.7
Coal with 30% carbon storage	7.7	7.2	1.7	16.6	5.9	7.2	1.7	14.8	3.7	7.2	1.7	12.6
Oil diesel	1.7	19.0	1.2	21.9	1.3	19.0	1.2	21.5	0.8	19.0	1.2	21.0
Nuclear	8.4	0.0	1.5	9.9	6.4	0.0	1.5	7.9	4.0	0.0	1.5	5.5
Geothermal	4.1	0.0	1.4	5.5	3.1	0.0	1.4	4.5	2.0	0.0	1.4	3.4
Wind onshore	6.6	0.0	2.2	8.8	5.2	0.0	2.2	7.3	3.5	0.0	2.2	5.6
Wind offshore	33.2	0.0	3.6	36.8	25.8	0.0	3.6	29.5	17.3	0.0	3.6	20.9
Solar PV	12.3	0.0	1.5	13.8	9.6	0.0	1.5	11.1	6.4	0.0	1.5	7.9
CSP	20.2	0.0	2.9	23.1	15.8	0.0	2.9	18.7	10.5	0.0	2.9	13.4
Waste to energy	16.7	0.0	7.6	24.3	13.4	0.0	7.6	21.0	9.5	0.0	7.6	17.2
Hydro (> 10 MW)	4.2	0.0	0.4	4.7	3.2	0.0	0.4	3.7	2.0	0.0	0.4	2.5
Hydro (< 10 MW)	3.0	0.0	0.9	3.9	2.5	0.0	0.9	3.4	1.9	0.0	0.9	2.8
Biomass POME	3.9	0.0	2.0	5.9	3.1	0.0	2.0	5.1	2.2	0.0	2.0	4.2

Notes: Cost assumptions and sources underlying these LCOEs are discussed in Section 3.2.2 and Table 6.4. OM = operations and maintenance costs.

Table 6.3: Levelised cost of electricity (in USD/kWh) (2016, 2025 and 2035)

Type	2016			2025			2035		
	10%	7%	3%	10%	7%	3%	10%	7%	3%
Single cycle*	0.070	0.063	0.056	0.065	0.059	0.052	0.062	0.057	0.050
CC*	0.121	0.115	0.107	0.113	0.107	0.100	0.109	0.103	0.096
Coal large*	0.070	0.065	0.059	0.065	0.060	0.054	0.062	0.057	0.052
Coal small*	0.105	0.097	0.087	0.096	0.089	0.080	0.092	0.085	0.076
Coal with 30% CC**	0.166	0.148	0.126	0.141	0.125	0.107	0.128	0.114	0.097
Oil diesel*	0.219	0.215	0.210	0.219	0.215	0.210	0.219	0.215	0.210
Nuclear	0.108	0.088	0.064	0.106	0.086	0.063	0.105	0.085	0.063
Geothermal***	0.081	0.067	0.051	0.081	0.067	0.051	0.081	0.067	0.051
Wind	0.088	0.073	0.056	0.088	0.073	0.056	0.055	0.046	0.035
Wind offshore	0.368	0.295	0.209	0.368	0.295	0.209	0.368	0.295	0.209
Solar PV	0.138	0.111	0.079	0.138	0.111	0.079	0.066	0.053	0.038
CSP	0.231	0.187	0.134	0.231	0.187	0.134	0.108	0.087	0.063
Waste to Energy	0.243	0.210	0.172	0.243	0.210	0.172	0.243	0.210	0.172
Hydro (> 10 MW)	0.047	0.037	0.025	0.047	0.037	0.025	0.047	0.037	0.025
Hydro (< 10 MW)	0.039	0.034	0.028	0.039	0.034	0.028	0.039	0.034	0.028
Biomass POME	0.059	0.051	0.042	0.059	0.051	0.042	0.059	0.051	0.042

Note: Projections are based on reduction in levelised costs of electricity assumed in EPRI (2015) and IRENA (2016) (see Table A3 in Appendix 6.1). CC = Combined Cycle. EPRI = Electric Power Research Institute. IRENA = International Renewable Energy Agency. POME = Palm Oil Mill Effluent. PV = Photovoltaic. CSP = Concentrated Solar Power.

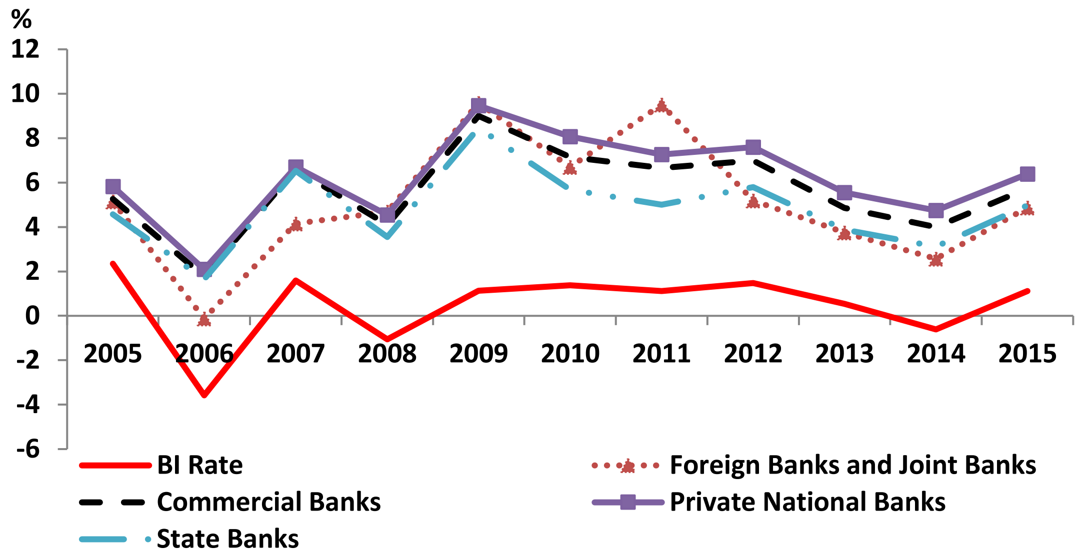
6.2.4 Interest rates and general economic assumptions

One major determinant of the LCOE is the choice of the discount rate, which is assumed to be in the range of between three and 10 per cent for the Indonesian context. The reason for this range is that there is a significant interest rate differential between the risk-free Bank Indonesia policy rate and commercial private and state banks.

This interest gap has been a longstanding macroeconomic phenomenon (see Figure 6.2). Average monthly real lending rates for investment loans of private banks during the period 2015–2016 were 7.1 per cent per annum. They were 6.4 per cent for commercial banks. Even state-owned banks offered around 6 per cent in the same period. Bank Indonesia's real policy rate was 1.6 per cent during the same period, meaning a gap of 3–5 per cent per annum. The preceding period from 2010–2014 (on an annual basis) showed a similar interest differential (see Figure 6.2).

Moreover, Indonesia's lending rates are also higher than in most countries in Asia and the spread between government bond yields and commercial lending rates is high compared to other countries (World Bank 2016). Business operates in a high-interest environment in Indonesia, reflecting the risk premium investors are putting on the Indonesian economy. This has been a longstanding problem and points to inherent weaknesses in Indonesia's banking sector and investment climate, which in turn affects specific investment in renewables.

Figure 6.2: Real investment lending rates and Bank Indonesia policy rate (2005–2015)



Source: Bank Indonesia, various issues.

The range of discount rates used here does reflect the existence of this risk premium. PLN seems to operate at the lower end of the discount rates, given that it not only receives electricity subsidies but has access to lower-interest rate loans from both state-owned banks and international donor agencies. Moreover, the utility is backed by the government in providing a vital public service, which makes it a safer investment choice when compared to other SOEs. Private IPPs, in contrast, often cite that they need to factor in returns of at least 15 per cent to run their projects (PWC 2011) to include regulatory risks (see Chapter 3). Some IPPs interviewed for this research borrowed money using a mixture of loans from domestic private banks and international loans at lower rates of between 1–3 per cent. Thus, the range of discount rates used here account for the different costs of capital that PLN and IPPs face.

6.2.5 Power plant cost data and assumptions

Detailed investment, OM and fuel costs for Indonesian power projects are not readily available in the academic literature. The most detailed cost estimates can be found in two papers by Wijaya and Limmeechokchai (2011). Those papers quoted several sources, which include reports from BATAN (2002), PLN (2005), IEA (2002), for coal, gas, combined cycle, nuclear generation costs, and a paper by Sanyal (2004) on geothermal investment costs. However, these data do not reflect the investment conditions in

Indonesia, particularly the financial and economic conditions prevailing under FTP 1 and 2 in the period 2006–2014.

The present thesis used Indonesian cost data sourced from World Bank (2015), media reports on power projects in 2011–2014, unpublished feasibility or pre-feasibility studies from donor agencies and industry players, and primary sources in the form of interviews with IPPs. In total, cost information was collected for 20 projects across six fuel technologies, namely coal, gas, geothermal, large hydropower, small-medium hydropower (up to 10 MW), biomass and WTE projects (see Chapter 3). However, these data are not coherent and complete datasets. For example, overnight capital/investment costs are generally readily available for almost all generation technologies or could be derived from industry and media reports, but data on OM costs, fuel expenditures, capacity factors and financing costs were not available for all technologies.

To ensure a coherent and more recent set of data, the author used international data on power plant costs to 'benchmark' Indonesian costs and to provide the base to calculate LCOEs, with available Indonesian information on plant costs used to 'contextualise' them. These data on various cost components have been obtained from international studies on electricity generation costs, notably from the following reports: 'Renewables 2016: Global Status Report' (REN21 2016), 'Power to Change: Solar and wind Cost Reduction Potential to 2025' (IRENA 2012f) and 'Renewable Power Generation Costs in 2012: An Overview' IRENA (2012a) and two country-specific studies from the US (EIA 2015) and Australia (Electric Power Research Institute 2015). Tables A1–A3 in Appendix 6.1 show the summary of data on power plant costs of these studies.

Table 6.4 summarises the cost data used to calculate the LCOEs for this research. All data are in 2015 USD prices. In the following sections, the specific data for each generation technology are discussed in more detail.

Table 6.4: Cost assumptions for power plant investment in 2016 (USD 2015 prices)

	COD / Year	Overnight investment cost USD/kw	Fixed OM USD/kW	Variable OM USD/MWh	Fuel costs USD/kWh	Installed capacity MW	Capacity factor (CF) %	hours	Heat rates kJ/kW	Plant efficiency
Single cycle [i]	2015	1077	17.1	3.4	0.04	100	50%	4380	9960 [i]	0.34 [ii]
Combined cycle [i]	2018	1080	9.78	1.96	0.09	429	48%	4231	6600 [i]	0.56 [iii]
Coal large ultra supercritical [ii]	2015	1400	33.75	1.875	0.04	650	80%	7008	11749	0.41 [ii]
Coal small[ii]	2015	1760	61.3	2	0.06	20	60%	5256	14063	0.26
Coal with 30% CCS [i]	2019	5098	68.49	6.95	0.07	340	80%	7008	9750	0.29
Oil diesel [i]	2015	700	17.94	7.98	0.19	0.7	50%	4380	n.a	n.a
Nuclear [i]	2022	6108	98.11	2.25	0.01	2234	88%	7709	n.a	n.a
Geothermal *	2015	4535	181	n.a	n.a	50	93%	8147	n.a	n.a
Wind onshore [i]*	2015	1280	45.98	n.a	n.a	100	24%	2129	n.a	n.a
Wind offshore [i]*	2015	6331	76.1	n.a	n.a	400	24%	2102	n.a	n.a
Solar PV *	2015	1624	21.33	n.a	n.a	150	17%	1454	n.a	n.a
Concentrated solar power (CSP) *	2015	4423	70	n.a	n.a	100	28%	2409	n.a	n.a
Waste to Energy [i]	2018	8511	403.97	9	n.a	50	69%	6001	n.a	n.a
Hydro (> 10 MW) *	2019	3148	14.7	2.62	n.a	500	90%	7884	n.a	n.a
Hydro (< 10 MW)**	2016	1607	65.1	n.a	n.a	2.8	80%	7008	n.a	n.a
Biomass POME ^	2015	2461	147	n.a	n.a	2.1	85%	7446	n.a	n.a

Sources: [i] US EIA (2016): US Capital cost estimates in 2016 at http://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf

[ii]Asian Development Bank and World Bank (2015)

*REN 21 (2016: 82-85): Table 2

** Actual project cost from ADF (2014)

*** Indonesian media reports, unpblished industry reports and interviews. USD costs for a range of years from 2009-2014.

^ IRENA (2012: 68)

*REN 21 (2016: 82-85): Table 2

Single cycle and combined cycle power plant overnight investment costs, fixed and variable OM, installed capacity and capacity factors costs were taken from EIA's (2015) report, which provides comprehensive capital cost data base from its survey of power plants in the US (see Table A1 in Appendix 6.1). Unit fuel costs of 4.4 and 9 cents/kWh for both plants were calculated using the appropriate heat rates, plant efficiency rates and capacity factors (see Table 6.4 and also explanation under equation (1) and (2) in Section 6.2.2). A natural gas price of 10.96 USD/MMbtu was used, which was the average price for the period 2015–2016.

Indonesian cost data for both single cycle and combined cycle plant seem to be higher, reportedly between 1,700–2000 USD/kW for the former and up to 2,500 USD/kW, although the data are from 2012 (see Appendix 6.2 for a brief discussion of Indonesian data reported in the media).[96]

Coal-fired power plant costs and capacity data for large ultracritical power plant were obtained from EPRI's (2015) report. Table A2 in Appendix 6.1 summarises the main cost data obtained from that study. Cost data were converted from AUD to USD using average exchange rate of 0.75 US$/AUS$ in 2015.[97]

The cost data for small power plants were taken from a World Bank (2015) report which provided cost estimates for small coal power plants with a capacity of less than 50 MW.

Using the capacity factors, heat and efficiency rates (see Table 6.4), unit fuel costs of 4, 6 and 7 USD cents/kWh were calculated, using a coal price of 60 USD/t, which was the average domestic price in 2015 under the *Indonesian Coal Price Reference* scheme (more commonly known as *Harga Batubara Acuan*).

Indonesian data on coal-fired power plants seem to be lower at 1,200–1,500 USD/kW (see Appendix 6.2), but they do not represent ultracritical or supercritical technologies, which the government of Indonesia has announced to prefer for future investments.[98]

---

[96] The information and data is based on 'Indonesia PLN eyes power plant near Sulawesi LNG project', *Reuters news*, 16 October 2012, http://www.reuters.com/article/2009/08/25/pln-indonesia-gas-idUSJAK44748820090825. See also http://southeastasiainfra.com/medco-to-provide-65-million-to-fund-a-70-mw-gas-fueled-power-plant-in-batam/.

[97] Using pacific exchange rate database at http://fx.sauder.ubc.ca.

[98] 'Government requires coal-fired producers to use clean coal', *Jakarta Post*, 11 June 2016, http://www.thejakartapost.com/news/2016/09/06/govt-requires-coal-fired-power-producers-to-use-clean-coal.html.

Overall, the calculated LCOE range of 6.6–10.5 cents/kWh for coal-fired generation seem to fit the Indonesian context: the latest price regulation for coal-fired power (i.e., the price at which PLN is mandated to buy) is in the range of 6.3–1.8 cents/USD.[99]

The data for coal with carbon storage, a relatively new technology for Indonesia, were taken from the EIA (2015). No comparable information from Indonesia has been obtained, but it has been included as a new technology option in Indonesia's long-term planning.

Diesel/oil-based generation cost data were sourced from the World Bank (2015). The low 700 USD/kW for investment costs represents typical diesel generator, which are used in islands outside of Java and have smaller capacity. The fuel price was taken from the World Bank's (2015) report, which was estimated at 19.28 US cents/kWh (World Bank 2015, p. 27).

Nuclear power data were entirely taken from EIA (2015). No nuclear power plants are in the current pipeline of projects in Indonesia, although there is a high-level policy commitment to keep nuclear power as an option to achieve emissions reduction targets, but only if the optimal use of all other fossil fuel–based and RE resources have not achieved a reduction of emissions targets and the targeted increase share of renewables in the energy mix. The national utility PLN estimates that the current investment costs are in the order of 6,000 USD/kW, in line with EIA (2015). But PLN argues that the costs of nuclear power development are still prohibitive for Indonesia and cannot compete with ultra-supercritical coal technology, if costs of safety standards and nuclear waste management are factored in (PLN 2015, p. 85).

Geothermal plant costs were taken from REN21's (2016) report, which presented a range of costs based on a survey of existing project in the world. The investment cost of 4,535 USD is a weighted average of costs of surveyed projects in Asia. Available data from Indonesian media reports suggest that investment costs (or overnight capital costs) have been found to be in the range of 2,100–4,600 USD/kW, with generation capacities of individual projects ranging from 40–440 MW (see Appendix 6.2). These varying

[99] MEMR MR No. 3/2015.

geothermal project costs are very much driven by size, location and the drilling costs determined by the number and productivity of the wells.

Wind power cost range is taken from REN21 (2016), but investment and OM cost data for onshore and offshore wind power plants were taken from EIA (2015). No concrete project data from Indonesia were obtained.

Solar power cost data from REN21 (2016) were used as the basis for calculating LCOEs for solar PV and CSP but supplemented by the installed capacity and OM costs provided in EIA's (2015) report. REN21 (2016) provides an investment cost range of between 819–2,784 USD/kW for investment costs of solar PV surveyed in Asia. The mid-cost of 1,624 USD was taken for the purpose of this study. However, it should be noted that capital costs of solar fell by as much as 58 per cent between 2010–2015 (IRENA 2016, p. 10). The estimated LCOE range of 8–14 cents/kWh falls within Indonesia's last differentiated FIT regulation in 2016, which stipulated a range of 14–23 cents/kWh, taking account of regional factors.[100] As discussed in Chapter 3, the latest FIT regulation has not specified differential FIT, but mandates tariffs to be set as a percentage of PLN's BPP, effectively forcing IPPs to agree on PPA prices below the cost of supply of coal or gas-fired generation.

Large hydropower plant (larger than 10 MW) cost data were taken from REN21's (2016, p. 83) report. The chosen data represent weighted average costs of projects surveyed in Asia, which encompass both small and large-scale hydropower plants. Available data sources from Indonesia seem to be higher than the chosen medium cost of 1,412 USD/kW. For example, an investment cost of 2,200 USD/kW was reported for the 195 MW Poso II project operated by PT Poso Energy in Central Sulawesi in mid-2013 (see Appendix 6.2).

The latest regulation on power purchasing prices for hydropower with a capacity larger than 10 MW state a price range of 8–9 cents/kWh, which indicates that the calculated LCOE of 2.5–4.7 cents/kWh is probably too low or represents the minimum busbar cost for developers.[101]

---

[100] MEMR MR No. 19/2016.
[101] MEMR MR No. 3/2015.

Small hydropower (< 10MW) data were obtained from an actual planned Indonesian project, the 2.8 MW run-of-the-river hydroelectric power plant in Ponggang, West Java. The plant is projected to start in 2017, co-financed and developed by IBEKA and French energy firm ADF Suez (GDF Suez 2014). The investment cost data of US$1,607 is lower compared to other projects in Indonesia but falls within range stated by REN21 (2016).

WTE power plant cost data for a landfill to energy plant were taken from EIA's (2015) report. The cost data from the US are likely to be overestimated, as information from Indonesian projects were reportedly lower. For example, the investment cost of 3,200 USD/kW is based on a landfill gas-to-electricity project operated by PT Navigat Organic in Bekasi, West Java in 2012 (see Appendix 6.2). As a result, the estimated LCOE range of 17–24 cents/kWh (see Table 6.4) is likely to be too high.[102] The FIT regulation for landfill projects stipulates a FIT of 1,598 IDR/kWH or 12.3 cents/kWh (using an exchange rate of 13,000 IDR/USD).[103]

Biomass POME power plant investment and OM costs for a POME-based power generation plant were taken from IRENA (2012). They represent costs for boiler (either using bubbling fluidised bed, BFB, or circulating fluidised bed, CFB, technology). An installed capacity of 3 MW was assumed, based on an unpublished feasibility assessment of the average potential power production capacity of 18 palm oil mills operating in East Kalimantan province (Global Green Growth Insitute 2016). The 2014 FIT regulation for biomass power generation stipulates a minimum FIT of 11.5 cents/kWh, which is above the calculated LCOE range of 4–6 cents/kWh, indicating that the FIT price is quite attractive for POME producers.[104]

It should be noted that all the cost estimates are subject to confidence intervals, and that costs might vary across Indonesia.

[102] If one assumes a lower investment cost of 3,200 USD/kW, but maintaining the EIA (2015) fixed OM cost data, the LCOE would be around 11.5 US cents/kWh. However, no consistent fixed and variable OM data from Indonesia projects could be obtained.
[103] MEMR MR No. 27/2014.
[104] MEMR MR No. 19/2013.

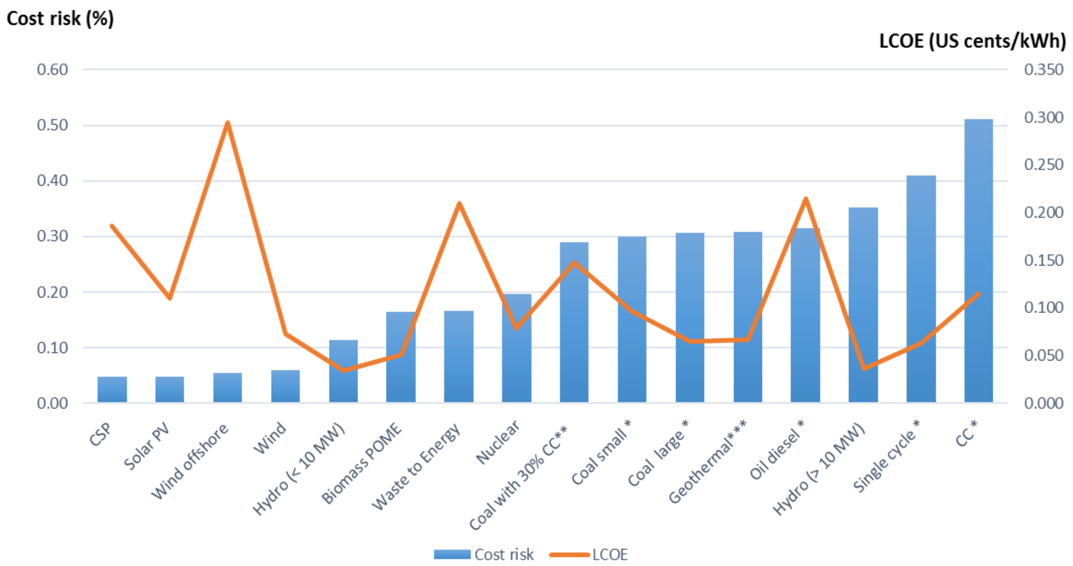
6.3 Cost risks

It is important to note that LCOEs present a least-cost and standalone cost perspective. Moreover, they are mainly driven by international benchmark prices, which do not fully account for local cost factors. The calculated LCOEs (see Figure 6.1 and Table 6.2) suggest that most renewables are already competitive with fossil fuel–based generation like single cycle gas and large coal plants. But what if other risks are considered to allow for a more complete picture of how generation technologies should be properly assessed? This section will present cost risks associated with generation technologies.

Cost risk is defined as the variability of cost streams of each generation technology. Standard deviations of past cost streams—namely capital/construction, operation, and maintenance and fuel costs—are presented as percentages and are divided by the levelised costs. Cost risk is calculated using the weighted average of three standard deviations measuring construction (capital) risk, fuel risk and OM risk. Almost all standard deviations for measuring capital/construction, fuel and OM used for the Indonesian case are taken mainly from Awerbuch and Yang (2008), as Indonesian data were not available. Some of the estimated standard deviations, mainly fuel risks for fossil fuel–based generation technologies and capital/construction risk for geothermal power generation, have been adjusted based on the author's research and interviews with IPPs.

Figure 6.3 and Table 6.5 show the cost risks associated with each generation technology at a seven per cent discount rate. Several broad trends can be detected. First, the lowest cost risks are associated with wind (onshore and offshore), solar (CSP and PV) and small hydropower. This can be mainly explained by the absence of fuel price risks and the low standard deviations assumed for capital/construction.

Figure 6.3: Levelised costs of energy (LCOE) and cost risks at seven per cent discount rate



Source: Author's calculations from data in Table 6.5.

Second, the highest risks are associated with technologies exposed to fuel price risks and that have large construction/capital risks, including renewables like large hydropower and geothermal.

Table 6.5: Cost risks for generation technologies in 2016

	Risk (standard deviations) [i]			Weighted average risk at:		
	Construction	Fuel	OM	10%	7%	3%
Single cycle	0.150	0.612*	0.105	0.385	0.409	0.442
CC	0.150	0.612*	0.105	0.491	0.510	0.536
Coal large	0.230	0.393*	0.054	0.298	0.306	0.317
Coal small	0.230	0.393*	0.054	0.294	0.300	0.307
Coal with 30% carbon storage	0.230	0.393**	0.054	0.283	0.290	0.300
Oil diesel	0.230	0.325*	0.242	0.313	0.315	0.317
Nuclear	0.230	0.240	0.055	0.204	0.197	0.183
Geothermal	0.380***	0.000	0.153	0.321	0.309	0.285
Wind	0.050	0.000	0.080	0.057	0.059	0.062
Wind offshore	0.050	0.000	0.080	0.053	0.054	0.055
Solar PV	0.050	0.000	0.030	0.048	0.047	0.046
CSP	0.050	0.000	0.030	0.066	0.047	0.046

Waste to Energy	0.200	0.180	0.108	0.171	0.167	0.159
Hydro (> 10 MW)	0.380	0.000	0.153	0.358	0.352	0.339
Hydro (< 10 MW)	0.100	0.000	0.153	0.112	0.114	0.117
Biomass POME	0.200	0.000	0.108	0.169	0.164	0.157

Notes: [i] Unless stated otherwise, the risk estimates are taken from Awerbuch and Yang (2008, p. 91) and are measured in percentage. * Calculated using fuel cost data from PLN annual statistics, ** Assumed to be same as for large coal power plants, *** 0.150 in Awerbach and Yang (2008, p. 91). OM = operation and maintenance costs.

6.4 Discussion

Do the calculated costs risks provide a realistic base for assessing investment risk associated with individual generation technologies in the Indonesian electricity sector? Several caveats need to be mentioned.

Construction and capital risk relate mainly to the complexity of financing and the length of constructing power plants. For Indonesia, the standard deviations for geothermal differ significantly from the literature. The standard deviation in the aforementioned literature is measured in percentage terms and assumes 0.150 for geothermal power plants, 0.230 for coal and 0.380 for large hydropower projects. However, these estimates were based on World Bank power projects in the 1980s and 1990s (Bacon, Besant-Jones, Heidurioni (1996) and used in the study by Awerbuch and Yang (2008). It can be argued that the delays of many of the coal and geothermal projects in the FTPs require significantly higher risk estimates (see Chapter 3). In the case of geothermal power projects, Chapter 1 showed that the targets under FTP 2 were achieved by the end of 2014. Thus, a far higher standard deviation is warranted, at least in the same magnitude of 0.380 given to hydropower projects. Similar arguments could be made for large coal power plants, although an exact record of these delays has not been established here.

One particular risk implied in capital risk is exchange rate volatility. As discussed in previous chapters, the Asian Financial Crisis brought many large power projects (mainly in the geothermal sector) to a halt, as PLN was not able to service foreign-denominated debt and subsequent protracted settlement and restructuring negotiations have undermined investor confidence in the electricity sector (Wells & Ahmed 1997). Exchange rate risks and losses remain significant for PLN (see Chapter 3), as SOEs like

PLN have not applied hedging practices when signing on PPA and loan agreements. In fact, only in 2015 did the government allow SOEs to apply hedging in their financing practices. PLN estimates that at least 20 per cent of the utility's annual investment needs of US$7 billion need to be hedged to enable the financing of the 35 GW expansion program. PLN signed a hedging facility agreement with state banks Bank Mandiri, Bank Rakyat Indonesia and Bank Negara Indonesia worth US$950 million.[105]

Despite allowing for hedging, PLN and the government are still bearing significant exchange rate risks in large coal-fired generation projects (Auriga 2017). The reason for this is that the cost of hedging needs to be accounted for and for Indonesia it is estimated that these costs are in the range of 9–13 per cent of the cost of total debt of a project. For example, the PPP-funded 2,000 MW coal-fired generation project in Batang, Central Java, has a total debt of US$3.4 billion which will result in significant additional costs for the government as the government provides the last guarantee in case of non-payment of debt by PLN. Thus, currency risk is not evenly shared between the government and the developer, implying an implicit subsidy for the project (Auriga 2017, p. 5).

For large hydropower projects, the 0.380 standard deviation seems appropriate for Indonesia, given that large hydropower is a capital-intensive enterprise, fraught with the same investment uncertainties as geothermal projects, thus justifying a relatively high—risk estimate. In particular developers face challenges in land acquisition and investing in transmission lines, as most hydropower sites are in remote areas and need to be connected to urban areas with higher water consumption rates. Regulatory challenges also add to capital/construction risks. For example, MoEF MR No. 64/2013 mandates that permits are required for water use in many potential hydropower sites in wildlife reserves, national, forest and tourism parks.

The standard deviations for biomass POME-based generation are ambiguous, as Awerbuch and Yang (2008, p. 91) have not specified what type of biomass power generation technology has been used to estimate the standard deviation. It could be argued that the standard deviation for POME-based generation should be smaller, given

[105] See 'PLN hopes to hedge 20% of yearly investment needs', *Jakarta Post*, 5 August 2015.

that most projects are small scale, off grid, and mostly run by palm oil plantation firms which produce electricity for their own operations and sell excess power to PLN.

Risks attached to nuclear power should be higher for the Indonesian context, given the absence of sufficient political support for projects, the likely high cost of importing nuclear technical and management expertise, and the risks associated with nuclear waste management.

Risk estimates associated with OM expenditures are all taken from Awerbuch and Yang (2008, p. 91). As these authors argue, these data are mostly corporate records and are rarely publicly available. This is even more true in the Indonesian context. Moreover, OM numbers can be biased towards achieving corporate objectives. This can be achieved by under-reporting OM costs for one period to record better financial performance (Awerbuch & Yang 2008, p. 92). Moreover, there are no scale effects between small and large coal plants, as risk estimates for construction and OM costs are assumed to be the same, as mentioned earlier in Table 6.5.

Fuel risk is mainly determined by the volatility of fuel prices. Proportional standard deviations have been calculated for gas, diesel and coal by using annual unit fuel price data in the PLN Annual Statistics from 1987–2015. Fuel risk estimates are assumed to be zero for solar, wind, hydro and geothermal, as they do not rely on fossil fuel inputs.

Some caveats related to fuel risks are in order though when applying the standard deviations for oil, coal and gas. First, (proportional) standard deviations are higher over a longer time series (see Table 6.6). For the purpose of this research, the 2010–2015 price trends have been used to reflect more recent fluctuations, which show smaller volatilities for diesel and coal prices compared to natural gas.

Table 6.6: Standard deviations for PLN fuel costs

Period	Diesel	Coal	Natural gas
2000–2016	0.666	0.600	0.669
2010–2015	0.325	0.393	0.612

Note: Diesel is average of High-Speed Diesel (HSD), Intermediate Diesel Oil (IDO) and Marine Fuel Oil (MFO) prices.

Second, although fuel price risks are here defined in terms of PLN's fuel costs, these risks should be seen from a systemic perspective, that is from the whole energy sector, which includes both PLN and IPPs. Given the dominant position of PLN as a buyer of electricity, as shown in previous chapters, it can be argued that fuel price risks directly affect IPP risk mitigation strategies. This is the case because PLN hesitates to enter PPA agreements until it has secured a purchasing tariff that is in line with its expectations about the size of its revenues, including the PSO subsidy. As shown in Chapter 3, PLN has its own internal fuel price expectations about diesel, coal and natural gas prices which in turn affects its rationale for speeding up or slowing down PPA power projects.

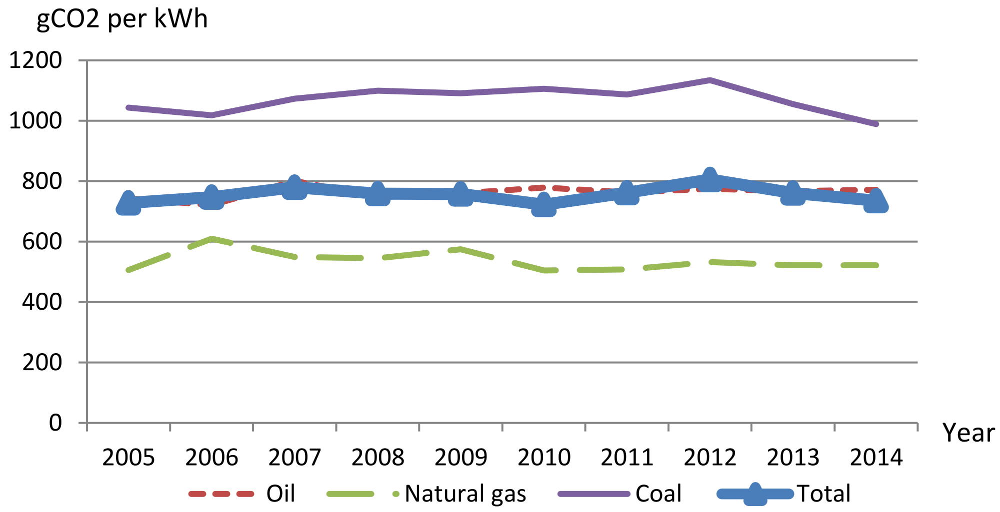
Generally, cost risk is driven by the interaction between the risk coefficient (the standard deviations) and movements in the discount rate. As mentioned earlier, interest rate assumptions affect only the capital investment cost component (see equation (1) in Section 6.2.2). For fossil fuel–based technologies, a lower discount rate results in higher cost risks, reflecting the fact that fuel price risks tend to outweigh the construction/capital risks (see Table 6.5). For renewables, the outcome is more ambiguous, even without the fuel price risk. A lower discount rate means that construction/capital investment cost component should lower cost risk. This is clear with geothermal and large hydropower, where the high standard deviation attached to construction reinforces the interest rate movement. Solar PV and CSP show the same declining cost risk, as the construction risk is higher than the OM risk. But onshore and offshore wind show the reverse trend, with lower discount rates resulting in higher risks, because the higher risk coefficient attached to OM cost component outweighs the risk to construction cost (see Table 6.5).

From a cost risk perspective, CO2 emissions represent long-term social costs associated with fossil fuels. In addition, future regulations might be imposed to limit carbon emissions. Those costs could be factored in by PLN by putting a carbon market price on those emissions, thus changing the relative cost risks between fossil fuels and renewables.

Carbon dioxide emissions from the electricity sector have steadily increased in Indonesia, from 16 to 168 million tons from 1990–2014 (see Figure 2.7 in Chapter 2). PLN (2016b, p. 169) projects total CO2 emissions from electricity generation to further increase to 395 tons by 2025, with coal-fired power generation accounting for 80 per cent of those emissions.

Emissions intensity of fossil fuel–based generation—that is CO2 emitted per kWh of electricity produced—has averaged around 755 gCO2/kWh in 2005–2014 (see Figure 6.4) but is projected to increase to 959 gCO2 by 2025 (PLN 2016b, p. 170).

Figure 6.4: CO2 per kWh of electricity and heat in Indonesia



Source: OECD and IEA database at http://www.oecd-ilibrary.org/energy/data/iea-co2-emissions-from-fuel-combustion-statistics_co2-data-en.

6.5 Conclusion and outlook

This chapter has calculated LCOEs and cost risks associated with generation technologies in Indonesia. The findings of the chapter contribute to the wider literature on risk assessment in the energy sector by providing a broader measurement of cost risk in the electricity sector. Cost risk goes beyond a traditional least-cost perspective and factors in wider risks associated with investing in power plants. Moreover, the use of cost risk—as a prerequisite for applying portfolio risk assessment—complements the purely qualitative risk assessment framework applied in PLN's planning documents.

From a LCOE perspective, most renewables are already competitive with coal and diesel (oil) fired generation. Prices of most renewables, notably geothermal, hydropower and solar PV, are competing in the 3–8 cents/kWh price range across all discount rates. The fall in the cost of renewables, especially solar and wind power, has been particularly strong in recent years and is likely to continue in future. This suggests that, even from a least-cost perspective, PLN should seriously start to consider taking up renewables on a larger scale than planned under current RUPTL scenarios.

From a cost risk perspective, lowest levels of risk are associated with wind (onshore and offshore), solar (CSP and PV) and small hydropower. This can be mainly explained by the absence of fuel price risks and the low standard deviations assumed for capital/construction.

The highest risk levels are associated with those technologies that are tied to fuel price risks and have large construction/capital risks, including renewables like large hydropower and geothermal.

A lower discount rate means higher relative cost risks for fossil fuel–based technologies, as fuel risks outweigh construction/capital investment risks. Conversely, a lower discount rate decreases financial risk for renewables with high risk attached to construction/capital investment and lower OM risks, as in the case of geothermal and large hydropower. For smaller renewables, the outcome is more ambiguous, depending on the size of the risks attached to construction and OM risks respectively.

Overall, even as renewables are already competitive in levelised cost terms, their higher upfront costs are still high. This suggests that given PLN's financial constraints, regulatory mechanisms such as FITs are still required to incentivise RE investment. Moreover, policies that reduce higher capital/construction risks could be very influential in lowering the financial risks of renewables with large-scale impacts such as geothermal and large hydropower. As discussed in previous chapters, it is important to reduce policy and regulatory risks in specific sectors such as the financial sector (deepening lending capacities), geothermal and hydropower (provide risk guarantees and improve land acquisition policies), and solar and wind (FITs and reducing equipment costs).

Finally, given Indonesia's projected increase of CO2 emissions intensity in the power sector, carbon prices and emission costs become an additional cost risk factor.

The next chapter analyses the portfolio risks of PLN's long-term supply mix scenarios, including carbon price–related risks.

Appendix 6.1: Assumptions underlying levelised cost calculations

Table A1 : Performance characteristcis of US power plants, 2016

Technology	First Available Year1	Size (MW)	Lead time (years)	Base Overnight Cost in 2015 (2015 $/kW)	Project Contingency Factor2	Techno-logical Optimism Factor3	Total Overnight Cost (2015 $/kW)	Variable O&M5 (2015 $/MWh)	Fixed O&M (2015 $/ kW/yr.)	Heatrate in 2015 (Btu/ kWh)	nth-of-a-kind Heatrate (Btu/ kWh)
Coal with 30% carbon sequestration (CCS)	2019	650	4	4,649	1.07	1.03	5,098	6.95	68.49	9,750	9,221
Conv Gas/Oil Comb Cycle	2018	702	3	911	1.05	1.00	956	3.42	10.76	6,600	6,350
Adv Gas/Oil Comb Cycle (CC)	2018	429	3	1,000	1.08	1.00	1,080	1.96	9.78	6,300	6,200
Adv CC with CCS	2018	340	3	1,898	1.08	1.04	2,132	6.97	32.69	7,525	7,493
Conv Comb Turbine	2017	100	2	1,026	1.05	1.00	1,077	3.42	17.12	9,960	9,600
Adv Comb Turbine	2017	237	2	632	1.05	1.00	664	10.47	6.65	9,800	8,550
Fuel Cells	2018	10	3	6,217	1.05	1.10	7,181	44.21	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,288	1.10	1.05	6,108	2.25	98.11	10,449	10,449
Distributed Generation-Base	2018	2	3	1,448	1.05	1.00	1,520	7.98	17.94	9,004	8,900
Distributed Generation - Peak	2017	1	2	1,739	1.05	1.00	1,826	7.98	17.94	10,002	9,880
Biomass	2019	50	4	3,498	1.07	1.01	3,765	5.41	108.63	13,500	13,500
Geothermal	2019	50	4	2,559	1.05	1.00	2,687	0.00	116.12	9,541	9,541
MSW - Landfill	2018	50	3	7,954	1.07	1.00	8,511	9.00	403.97	14,360	18,000
Conventional Hydropower	2019	500	4	2,191	1.10	1.00	2,411	2.62	14.70	9,541	9,541
Wind	2018	100	3	1,536	1.07	1.00	1,644	0.00	45.98	9,541	9,541
Wind Offshore	2019	400	4	4,605	1.10	1.25	6,331	0.00	76.10	9,541	9,541
Solar Thermal	2018	100	3	3,895	1.07	1.00	4,168	0.00	69.17	9,541	9,541
Photovoltaic	2017	150	2	2,362	1.05	1.00	2,480	0.00	21.33	9,541	9,541

Source: US EIA Annual Energy Outlook 2016, Capital cost estimates at http://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf

Table A2: Cost estimates of Australian Power Plants (2015)									
	Plant costs A$/kW	550 ppm	450 ppm	Fixed OM A$/Mwh	Var OM A$/Mwh	Power capacity kw	**Capacity factor %**	**Efficiency %**	**heat rate kj/kwh**
	2015	**2030**	**2030**						
Brown coal, IGCC	6,150	5,634	5,634						
Brown coal with CCS	8,515	7,091	6,524						
Black coal, pulverised	3,100	2,783	2,783	45	3	650,000		41	8,800
Black coal, IGCC	5,000	4,863	4,863						
Black coal with CCS	7,000	5,462	4,908	55	9	461,400		30	12,000
Single cycle	1,000			8	12	278,296		34	10,600
Gas, combined cycle	1,450	1,406	1,409	20	2	442,002			
Gas with CCS	3,065	1,987	1,516						
Nuclear	9,000	8,974	8,876	100	2	1,100	19-32		
Solar thermal	8,500	3,916	3,903	65	4	125,000			
Rooftop PV	2,100	1,243	1,257						
253									
Large-scale commercial PV	2,300	1,108	1,128	25		50,000	19-32		
Wind	2,450	2,040	1,973	55		200,000	35-42		
Source: Electric Power Research Institute (EPRI, 2015): Tables 32 and 33									

Table A3: Projected LCOE reductions	EPRI 2015		IRENA 2016
	2035	2025 *	2025
Single cycle	**-10%**	**-7%**	**n.a**
Combined cycle	**-10%**	**-7%**	**n.a**
Coal large	**-13%**	**-8%**	**n.a**
Coal small	**-13%**	**-8%**	**n.a**
Coal with 30% CCS	**-23%**	**-15%**	**n.a**
Oil diesel	**n.a**	**0%**	**n.a**
Nuclear	**-3%**	**-2%**	**n.a**
Geothermal	**n.a**	**0%**	**n.a**
Wind onshore	**-37%**	**0%**	**-26%**
Wind offshore	**n.a**	**0%**	**-35%**
Solar PV (low cost range)	**-52%**	**0%**	**-59%**
Concentrated solar power (CSP)	**-53%**	**0%**	**-37%**
Waste to Energy	**n.a**	0%	n.a
Hydro (> 10 MW)	**n.a**	0%	n.a
Hydro (< 10 MW)	**n.a**	0%	n.a
Biomass POME	**n.a**	0%	n.a
Note" calculated from 2035 projections, assuming average			
annual growth rate			

Appendix 6.2: A survey of investment costs of power projects in Indonesia (2010–2013)

This appendix provides some cost estimates on Indonesian power projects collected from various media and project reports in Indonesia to provide some context for the period when most of the fieldwork interviews took place.

Coal-fired power projects

Paiton Thermal power plant: In March 2010, Japanese Bank for International Cooperation (JBIC) signed a project financing loan agreement with PT Paiton Energy, an Indonesian company in which Mitsui & Co., Ltd. (Mitsui) and Tokyo Electric Power Company, Inc. (TEPCO) have equity stakes. The company will sell the electricity generated in this plant for 30 years to PT PLN (Persero), a state-owned electricity company. Mitsui and TEPCO have undertaken developing Indonesia's large electric power sector infrastructure as an 'All Japan' package that encompasses their overall involvement in this project, including the development, operation and management of this project facilities. This plant adopts supercritical pressure technology to reduce CO2 emissions.[106]

Looking at the data available, total investment costs would be US$1.215 billion. A total capacity of 815 MW will be built, which is an extension of the currently operating 1,230 MW Paiton power station. This amounts to US$1.49 million/MW.

Coal fuel supply is estimated to be in the order of 110,000 tonnes per month for three years, amounting to a total of around 3.96 million metric tonnes for three years. If the average Indonesian coal price index (Harga Batubara Acuan) for 2010 is taken, then the price for coal is an average US$91.8/metric ton, while in 2012 the monthly average price would be US$118/t. The reported monthly coal supply is 110,000 tonnes. Thus, coal fuel expenses for the Paiton power plant would be in the order of US$10.9–12.9 million per month.[107]

[106] See Mitsubishi Press Information, 5 June 5 2012, http://www.mhi.co.jp/en/news/story/1206051543.html. See also PLN Press Statement, Coal Power Plant project 2x1000 MW in Central Java at http://www.pln.co.id/eng/?p=2607.
[107] Harga Batubara Acuan price trends can be seen at www.coalspot.com.

Cirebon thermal power plant: Total investment cost for the Cirebon thermal power plant is US$850 million. Total installed capacity will be 650 MW. Thus, investment cost is US$1.3 million/MW installed. Investment is financed by Korean Midland power with its Indonesian partner. There are no official reports that the project receives any international or door assistance, thus it is assumed to be a purely private company and loan financing is carried out under the average commercial lending rate of 12.4 per cent in Indonesia in 2011.

The power plant needs around 2.85 million tons of coal annually, which translates roughly into an annual fuel cost of US$85.5 million. The coal is supplied by Kideco, a subsidiary of Indika Energy, and publicly listed coal producer PT Adaro Indonesia. PLN president director Nur Pamudji said the state utility would buy the electricity produced by the new plant with a rate of 4.43 cents/kWh, with an assumption the coal prices was at US$30 per ton. However, he added, that PLN would buy the Cirebon plant-produced electricity at 5.2 cents/kWh given the present coal prices.[108]

PT Indonesia Pusaka Berau, a consortium between PT Pusaka Jaya Baru and PT Indonesia Power, announced an investment of IDR 140,000 million, approximately US$16.32 million, in the construction and development of a coal-fired power plant near its site in Lati, Berau, East Kalimantan, Indonesia. PT Indonesia Pusaka Berau is owned by the Berau administration, and PT Indonesia Power, a subsidiary of PLN. The project is an expansion of the existing 14 MW power plant, which was built in 2005.

The total installed capacity of the project will be 14 MW, comprising of two units of 7 MW each. The investment per MW of the project will be approximately US$1.17 million. The coal for the project will be supplied by PT Berau Coal under a special arrangement. The project is expected to absorb about 83,000 tons of coal annually, although a spokesperson of Berau coal is quoted that the exact amount of coal supplied to the power plant and the price will still be discussed further with the consortium. The construction of the power project is expected to start in 2011. The project is to become

[108] See 'Cirebon power plant on stream for Java and Bali', *Jakarta Post*, 9 October 2012, http://www.thejakartapost.com/news/2012/10/19/cirebon-power-plant-stream-java-and-bali.html.

operational in 2012.[109] Detailed financing plans were not disclosed in media reports, thus the average lending rate in Indonesia of 12.4 per cent in 2011 is applied here.

Gas-fired power generation

PT Medco Power, Batam: According to reports PT Medco Power Indonesia (Medco) has allocated US$120 million (out of which 50 million is for an underwater transmission line) to a (2x35 MW) 70 MW gas-fuelled power plant in Batam (Tanjung Uncang industrial area) to provide electricity to the island for a period of 20 years, starting in 2014.[110] Medco, through its subsidiary, Energi Listrik Batam, signed a purchase agreement with PLN Batam, a subsidiary of state electricity company PLN, on 15 October 2012. The contract obliges PLN to pay 2.81 cents/kilowatt hour to Medco, excluding payment for a gas fuel component. Medco's investment will cover the construction of the power plant (US$70 million) and the US$50 million for a 28-kilometre underwater pipeline that will connect the West Natuna gas block to Batam. The consortium of PLN Batam and Medco Power will manage the distribution of gas to the plant. Medco, though, is still waiting for approval from oil and gas regulator BP Migas to secure the gas supply from the West Natuna gas block. BP Migas determines the allocation of gas to consumers on an annual basis and most of the gas from the West Natuna gas block is sold to Singapore. No financial plans were disclosed, so an average commercial BI rate of 12.4 per cent of interest in 2011 is assumed.

PT Mitra Energi Batam combined cycle gas turbine:[111] This project converts two single gas turbines into a combined cycle gas turbine system at PT Mitra Energi Batam power station at Batam island. The combined cycle gas turbine power plant uses of heat of already existing turbines to generate steam to produce electricity. Planned installed capacity will be 20 MW to be effective in 2012. Around 145,669 MWh will be sold to the only buyer in Batam, PLN Batam power grid. Plant load factor is projected to be 84 per

---

[109] 'PT Berau Coal is ready to supply new coal-fired power plant', *Jakarta Post*, 21 July 2011. Bintoro Prabowo, a spokesperson of Berau Coal, said, 'The exact amount of coal we'll supply to the planned power plant and the price will be discussed further with the consortium'. See also 'PT Indonesia Pusaka to invest US$16 million in expansion of Lati Coal Power Plant in East Kalimantan, Indonesia', 20 July 2011, http://www.researchviews.com/energy/power/fossil-fuels/DealReport.aspx?sector=Fossil%20Fuels&DealID=171708.

[110] 'Indonesia PLN eyes power plant near Sulawesi LNG project', *Reuters*, 16 October 2012, http://www.reuters.com/article/2009/08/25/pln-indonesia-gas-idUSJAK44748820090825. See also http://southeastasiainfra.com/medco-to-provide-65-million-to-fund-a-70-mw-gas-fueled-power-plant-in-batam/.

[111] PT Medco Energi is the man shareholder of PT Mitra Energi Batam.

cent. The proposed investment cost and capital expenditure is US$48.5 million in 2011. Total annual OM costs is assumed to be at US$2.2 million. An electricity selling tariff of 285 IDR/kWh or 3.3 cents/kWh (at an exchange rate of 8500 IDR/USD in 2005) is proposed in the CDM document. A carbon price of US$25/metric ton of CO2e is factored into the tariff. The benchmark/market interest rate for the project is Bank Indonesia's average investment lending rate of 12.16 per cent from Jan–August 2011. The investment period assessed is 20 years.[112]

The project uses the CDM mechanism and obtains carbon credits in exchange for proven reduced CO2 emissions, which come mainly from the avoided emissions from building oil-, gas- or coal-based power plants. A carbon price of US$25/metric ton of CO2e is factored in to the tariff. Thus, it can be argued that the viability of the project is subsidised by external money. The estimated total LCOE for single gas is was 8.5 USD/kWh, compared to the lower tariff set at 285 IDR/kWh or 3.3 cents/kWh (at an exchange rate of 8,500 IDR/USD in 2010) (UNFCCC 2012b, p. 28). The gap is financed by the CDM mechanism. The benchmark/market interest rate for the project is Bank Indonesia's average investment lending rate of 12.2 per cent.

PT Ephindo (and GE), Coal Bed Methan Block (CBM) project in Sanggata CBM block, East Kalimantan: Using gas from the Sanaggata CBM, the power plant is expected to generate 1 MW of electricity in 2011. Total investment cost is estimated to be US$2 million (or 17.8 billion IDR) in 2010. PLN is expected to buy electricity from the CBM-based power plant at the mandated FIT rate in the range of 853–1,300 IDR/kWh (9.5–14.5 cents/kWh). Indonesia is estimated to hold 450 trillion cubic feet of CBM across 21 fields in the country. The field in Sanggata, which is controlled by Ephindo, is estimated to produce around 500,000 cubic feet per day.[113]

Geothermal power generation

Itochu Corporation, PT Kyushu Electric Power Company, PT Medco Power and Ormat Inc, Sarulla geothermal field, North Sumatra: These four companies have jointly

[112] The project's IRR with CDM is projected to be at 12.58%. Without CDM finance, the IRR is at 1.42% (UNFCCC 2012).

[113] See 'GE to develop first CBM gas fired-power plant in Indonesia', *Jakarta Post*, 8 October 2010, http://www.thejakartapost.com/news/2010/11/08/ge-develop-first-cbm-gas-firedpower-plant-indonesia.html. See also Dua sumur CBM Ephindo mulai berproduksi Akhir Agustus at http://www.indonesiafinancetoday.com/read/30367/Dua-Sumur-CBM-Ephindo-Mulai-Berproduksi-Akhir-Agustus.

established an operating company, Sarulla Operations Ltd, that has signed a 30-year PPA with PLN and an ESC with PGE PERTAMINA who is the holder of the concession for the Sarulla field. The project is assumed to start commercial operation in 2016.

The ESC includes the development of a geothermal resource concession owned by PGE in Indonesia's Sarulla region in North Sumatra, construction of a geothermal plant with a total capacity of approximately 330 MW and sales of generated power to PLN. PPA with the state-owned utility PT PLN with a price of power at 9 cents/kWh. Financial policy support to geothermal projects include: a seven-year income tax holiday and tax exemptions for the carbon credits generated from RE sources, a 10% corporate income tax, and a 1.5 per cent realty tax cap on original cost of equipment and facilities to produce RE.

Sarulla Operations Ltd will invest a total of US$1.4 billion to install 330 MW of geothermal generation capacity, of which 70 per cent or around US$1 billion will be provided by JBIC. Interest rate on JBIC loans is assumed to be the 1.4 per cent.[114]

PT Supreme Energy, with geothermal fields at Muaralaboh and Rajabasa: Supreme Energy is a private consortium, backed by Japanese conglomerate Sumitomo and International Power GDF-Suez. One plant is 220 MW of installed capacity and both plants are projected to be in commercial operation by 2016. Total investment for both plants is estimated to be at US$1.4 billion, with 650 million allocated to Rajabasa and 700 million to Muaralabah. Internal cash and commercial bank loans are the main source of project finance. The agreed 30-year PPA purchasing tariffs are 9.4 and 9.5 cents respectively, both below the mandated ceiling prices under the 2009 geothermal FIT regulation. Both PPAs were signed prior to the exploration and drilling of the geothermal fields, as mandated by the regulatory framework. Reportedly, the government provides a guarantee for the projects and will step in if PLN cannot pay the prices in future. Thus, project developer is shielded from the risk of PLN is defaulting.[115]

---

[114] See JICA's ODA loan project website: http://www2.jica.go.jp/en/yen_loan/index.php/module/search?anken_name=&area1=0&area2=0&area3=0&country1=12&country2=0&country3=0&section1=0&section2=0&section3=0&industry1=0&industry2=0&industry3=0&anken_kubun=0&chotatsu_kubun=0&from_year=&to_year=&submit=Search.

[115] 'Geothermal energy in Indonesia', *Jakarta Globe*, 3 March 2012; 'Sumitomo bets on Indonesia's growing need for electricity', *Jakarta Globe*, 7 February 2012, http://www.thejakartaglobe.com/archive/sumitomo-bets-on-indonesias-growing-need-for-electricity/496488/.

PGE (Pertamina Geothermal Energy), Lumut Balai geothermal field, South Sumatra: Exploration, drilling of geothermal wells and confirmation of CDM financing were finalised between 2007–2010. A PPA has been signed in March 2011, and PGE has started the construction of the 110 MW geothermal power plant in July 2012, with the COD expected to be January 2015. The plant will produce an estimated 867 GWh per annum (UNFCCC 2012, p. 2). The total investment value of the projects is estimated to be US$230.2 million (or 2.1 million USD/MW). JICA agreed to financially support the project with a loan worth up to 27 billion Japanese Yen (around US$270 million), with an annual interest rate of 0.3 per cent and a repayment period of 40 years.[116]

Annual operation cost is expected to be US$8.8 million. PGE expected to be able to sell generated electricity to PLN at the price of US$90/MWh, in the feasibility study. However, in March 2011 the PPA was finally signed with a significantly lower price than expected, US$75.3/MWh or 7.53 cents/kWh (UNFCCC 2012, p. 11).

PGE, Ulubelu geothermal field, Units 3&4: The Ulubelu geothermal field is situated in the province of Lampung, on the island of Sumatera. The field is developed in two separate stages. In the first stage, Ulubelu Units 1&2 (110 MW) are being developed by PGE (upstream) and PLN (downstream). This stage is financed separately by JBIC (World Bank 2011d).

The proposed units 3 and 4 will be developed by PGE and consist of two supplementary 55 MW units in the second stage. Total investment costs (2010) for this 110 MW geothermal plant are US$359 million or US$3.3 million/MW. Annual OM costs are estimated to be US$20.7 million. The electricity tariff at which PLN buys is set at 7.53 cents/kWh. The project design document states that this price assumes that PLN receives the PSO subsidy, as the alternative investment into a coal-fired power plant would be cheaper as the tariff would be set at 6.4 cents/kWh (World Bank 2011d, p. 77–79). The project is financed by a loan from the World Bank (US$108.5 million), CTF (US$77.5 million) and from PGE's internal funds (US$140.2 million). The cost of financing is determined by the three interest rates, namely 5.02 per cent (IBRD), 0.25 per cent (CTF) and 14 per cent for PGE financing (based on estimated rate of return to geothermal

[116] JICA Press Release (2011, 29 March), 'Signing of Japanese ODA loan with the Republic of Indonesia', http://www.jica.go.jp/english/news/press/2010/110329.html.

investment by Pertamina). The weighted average cost of capital is estimated at a nominal 8.08 per cent (5.93 per cent).

PGE, Lahendong geothermal field: The Lahendong 5&6 (2 x 20 MW) units are being developed as an extension project of the adjacent green field to the existing Lahendong geothermal field (4x20 MW units) situated in the Minahasa area of the northeastern sector of Sulawesi island.

Total investment costs (2010) are reported to be in the order of US$184.3 million, which are shared between IBRD (50.2 million), CTF (35.8 million) and PGE (105.9 million), as in the Ulubelu project. Estimates for the interest rates are the same as for the Ulubelu project.

The cost difference between these two projects is mainly driven by the drilling costs per MW, which are significantly higher for the Lahendong project.[117]

All projects use a blend of external donor financing and private financing, thus the 10 and 15 per cent discount rate represents a realistic range for the opportunity cost of capital in the Indonesian context. Four out of the five projects are financed by external donor financing or the CDM mechanism, indicating that they would not be viable as standalone domestic private projects.

Large hydropower

PLTA Poso II and III, PT Poso Energy, Poso, Central Sulawesi: PT Poso Energy is a subsidiary of private conglomerate Kalla Group, led by former Vice President Jusuf Kalla. In 2008, the group constructed a 195 MW power plant, with total investment amounting to 4 trillion IDR or US$421 million (at an exchange rate of 9,500 IR/USD). This is an investment of around US$2.1 million per MW. The whole project was financed by local commercial banks without foreign assistance. The PPA price with PLN is 6.7 cents/kWh. PLTA Poso II is expected to go fully online in mid-2013.

A third plant with an installed capacity of 300 MW will be constructed from 2014 onwards, with completion within the 4–5 years. Investment is estimated to be in the

[117] These costs are in turn driven by the number of wells needed and the expected productivity per well (World Bank 2011d, p. 73).

order of US$600 million. This amounts to an investment value of 2 million per installed MW.[118] Although the PPA price not been announced yet, it is expected to be the same or close to the same price as under the previous PPA between Poso II and PLN (i.e., 6.7 cents/kWh). Interest rates for financing the project are assumed to be at 13.01 per cent, the average nominal lending rate in 2012.

PPP hydropower projects in 2013: Three large hydropower projects will be signed in 2013 by PLN under the PPP agreement. The Karama power plant will be built by PT Sulbar Group and China Gezhoumba Group with a total capacity of 450 MW and an investment of US$1.2 billion. The contract for the Kerinci plant has been awarded to PT Kerinci Hydro Energy with 450 MW capacity and US$510 million investment. In Batang Toru, Operational Cooperation Dharma Hydro will build the 500 MW power plant with an estimated total investment of US$1.2 billion. No detailed financing plans have been available to date, but the projects are eligible for government guarantees under the Indonesia Infrastructure Guarantee Fund and for external donor financing, at least for part of the total financing costs.[119]

Small-medium hydropower

SKE, Solok Selatan, West Sumatera: PT Selo Kencana Energi is a private developer operating a 7.5 MW hydropower plant in the district of Solok Selatan (South Solok), West Sumatra. The project will deliver electricity to PLN under a 25-year PPA. The project is forecast to reduce greenhouse gas emissions by an estimated 677,050 metric tons over its lifetime.[120]

Total investment is US$17.7 million (as of 2010), with construction starting in 2011 and COD is expected to be in 2013. The PPA was signed in 2010, with the tariff agreed with PLN falling within the mandated range of between 7.1–11.1 cents/kWh of the 2009 FIT regulation. SKE secured a US$1.8 million 'mezzanine' loan from USAID in April 2011. This loan will allow the developer to proceed with the US$17.7 million project under a 'limited recourse' financing scheme.

---

118 'Poso power Plant expected to boost C. Sulawesi's energy', *Jakarta Post*, 26 December 2012.
119 'Private companies to build 3 power plants', *Jakarta Post*, 21 March 2012. See also PT Pembangkitan Jawa-Bali website: http://202.154.61.204/pers-4-ppa-3-proyek-plta-diteken-2013.htm
120 Interview with Jamsa Suawardi, PT SKE. See also PFAN/USAID Environmental Cooperation at http://usaid.eco-asia.org/tools/weekly reports/news-detail.php?id=246.

PT Fajar Futura Energi, Rantabella, South Sulawesi: This IPP developed a small-scale hydroelectric power plant along the river at Rantabella village in South Sulawesi. The plant has a total capacity of 2.4 MW of electricity, which is fed into the South Sulawesi grid. The project started in 2005 with a feasibility study, the PPA was signed in March 2007, financial closure was submitted in December 2007, construction started in January 2008 and commercial operation started on 1 April 2010.[121]

Total investment costs amount to US$5.6 million or 2.2 million/MW. Annual OM costs are estimated to be US$292,000. The agreed PPA price with PLN is 8.3 cents/kWh. Financing is partly sourced from commercial banks and CDM finance with two Japanese companies (Chugoku Electric Power Corp. Inc and Kajima Corp.) buying the accredited carbon credits.

Landfill gas to electricity

PT Navigat Organic, Bantar Gerbang, Bekasi: The Bekasi municipality tendered out this WTE project in 2008, which was won by the private company PT Navigat Organic. Construction started in 2009, and the power plant at the Bantar Gebang dump site is scheduled to convert 5,000 tons of solid waste from Jakarta and surrounding areas into 26 MW of electricity by 2012. Total investment is estimated to be US$82 million (in 2010) or around US$3.1million/MW. The agreed PPA price is 820 IDR/kWh or 9.1 cents/USD (with an exchange rate of 9,000 IDR/USD). As an interview with the project developer suggests, this is not an economic price for the developer when the PPA was agreed on in May 2010, but the newly revised FIT for electricity produced by small/medium developers suggests that negotiating a higher price with PLN is still possible. Financing was obtained from Indonesian commercial banks, so the benchmark interest rate is the average nominal Bank Indonesia lending rate of 13.3 per cent in 2010.[122]

---

[121] Interview with Robert Batara, PT Fajar Futura Energi Luwur and DNV (Det Norske Veritas, 2010). 'Validation Report – Ranteballa Small-Scale Hydroelectric Power Project in Indonesia. Report No. 2008-1078. Revised Report (24 February 2010), http://cdm.unfccc.int/Projects/DB/DNV-CUK1268109841.14/view.

[122] Interview in September 2011 with Agus Nugroho Santoso, PT Navigat Organic, who anticipated the new FIT regulation, which was issued in January 2012 as a MEMR MR No. 22/2012. See also 'Energy Plans for Bekasi', *Jakarta Globe*, 10 March 2009; Tender Indonesia, http://www.tender-indonesia.com/tender_home/innerNews2.php?id=8789&cat=CT0009.

Chapter 7: Renewables and the Cost Risk of Power Supply: Stochastic Scenario Analysis

Abstract

This chapter uses MVP theory and numerical simulations to show the effects of diversifying the electricity supply mix. The MVP framework assesses the relative importance of generation technologies in terms of their contribution of their individual cost risk to the overall portfolio risk of the utility. Portfolio scenarios for 2025, 2035 and 2050 are evaluated based on electricity production targets of government planning documents such as the utility's RUPTL and the government's RUEN.

The results of the simulations suggest that cost differences are relatively small but the difference in levels of risk across the generation technologies is significant. Portfolios with strong renewables and combined with higher energy efficiency outcomes represent the most efficient baskets, as they optimise cost and risk minimisation. Conversely, portfolios with a small share of renewables present the costlier and riskier options. Higher discount rates have only a small impact on the risk and cost profiles, whereas inclusion of carbon prices increases the risks and costs for all portfolios but is more pronounced for those portfolios with a high share of fossil fuel–based technologies. Finally, an increase in the share of solar power technologies further reduces the costs and risks of the portfolios with a large share of renewables.

7.1 Introduction

The previous chapters have shown that PLN has not had many incentives to develop more renewables and has preferred to push the expansion of coal-based electricity generation. Chapter 6 showed that variations in cost streams translate into different cost risks and uncertainties associated with individual generation technologies. Generally speaking, higher volatility in fuel prices associated with fossil fuel–based generation makes renewables a more attractive option from a risk mitigation perspective. Higher cost risks associated with capital and construction cost components work against large capital-intensive renewables plants such as geothermal or large hydropower.

Within the Indonesian context and from a standalone LCOE perspective, PLN is rational in preferring coal and gas, given its financial constraints and the relative higher cost risk of large-scale renewables. But if energy planners are tasked to include more renewables in their supply mix scenarios, including cost risks can improve their investment decisions. Could diversifying the energy mix reduce the cost risk for Indonesia's energy system?

This chapter uses MVP theory and numerical simulations to show the effects of diversifying the electricity supply mix in the system. The MVP framework looks at the trade-off between average levelised generation cost (i.e., LCOEs) and risk—defined as cost risk—by providing a cost risk analysis of various long-term *portfolios* comprising of a mix of renewable and fossil fuel generation technologies.

The main reference point for modelling portfolio scenarios is the official planning document of the utility PLN, the RUPTL. The annual RUPTL is PLN's planning document for a period of nine years. The latest available electricity supply projection under the RUPTL is for the period 2016–2025. Additionally, the government has also released the RUEN, which formulates targets until 2050. Portfolio scenarios for 2025, 2035 and 2050 are developed, using the broad targets laid out in those documents.

Given that PLN only provides a qualitative risk assessment framework in its annual business plans, this chapter contributes to the literature in two ways. First, it provides alternative long-term power supply mix scenarios to the official PLN scenarios which allows for a comparison of various cost and risk outcomes ranging from renewable-rich to fossil fuel–rich ones. Second, it develops an energy portfolio model which provides a quantitative evaluation of the interaction between costs and risks—understood as *cost risks* or *cost uncertainty*—of individual technologies and PLN's energy portfolio as a whole.

Section 7.2 will briefly explain the relevance of portfolio analysis for the Indonesian electricity sector context. Section 7.3 describes the specifications of the model. Section 7.4 presents the three reference scenarios and 16 potential scenarios ranging from strong to weak renewables scenarios and including energy demand (energy efficiency) scenarios. Section 7.5 presents the simulation results. Section 7.6 discusses the findings and Section 7.8 concludes the chapter.

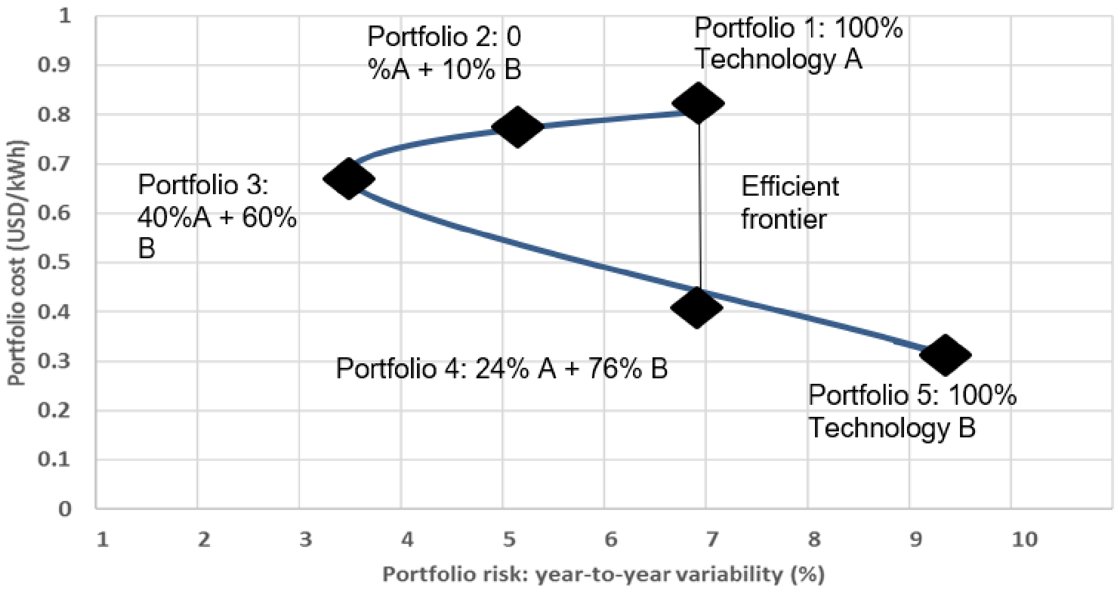
7.2 Methodology: Portfolio modelling in the Indonesian policy context

Chapter 6 provided an overview of portfolio theory, focusing on constructing the levelised generation costs and cost risks for generation technologies in the Indonesian electricity sector. The LCOE was calculated for each generation technology, using cost data assumptions from various international and national reports (see Table 6.4). The LCOEs were calculated for three cost components for each generation technology, namely OM, fuel and capital/construction costs. Then, a weighted average of these LCOEs were taken to see the share of each cost item in the total LCOE for each technology. Finally, these weighted average LCOEs were multiplied by a risk coefficient to arrive at the final variable—cost risk. The risk coefficient used is a standard deviation that measures the variability of the three cost streams of each technology. Most of these standard deviations were taken from secondary literature (as discussed in Chapter 6).

What is the relationship between cost and cost risk of a given portfolio? A simple example shown below to illustrate the potential benefits of diversifying energy portfolios.[123]

[123] This exposition closely follows Bazilian & Roques (2008).

Figure 7.1: Illustration of portfolio effect in the case of a two-technology portfolio



Source: Bazilian & Roques (2008, p. 67).

In Figure 7.1, costs and risks are allocated across various possible baskets containing combinations of two technologies A and B. Portfolio 1 contains 100 per cent of technology A (e.g., solar PV) at higher expected costs of 0.08 USD/kWh and lower risk in terms of variability of seven per cent. Portfolio 5 shows an energy basket containing only technology B (e.g., coal) at lower expected cost but higher risk. To simplify things, the correlation factor between the total cost streams of the two technologies is assumed to be zero. By moving from Portfolio 1 to 2, an investor chooses to replace 10 per cent of technology A with technology B, thereby reducing costs and risks. This trade-off continues by moving further to basket 3, which represents the minimum variance portfolio, as it is the best outcome in terms of minimising costs and risks. Investors would not move beyond Portfolio 3, because equivalent risks can be gained at lower costs. Portfolio 4 represents a better option than 1, because the same level of risk can be obtained at a lower cost. It also represents a more attractive option relative to Portfolio 5 (100 per cent coal) for investors, because portfolio risk can be reduced significantly at a relatively small increase in cost.

In applying MVP analysis, a caveat needs to be added. Portfolio analysis is very insightful in showing clear choices in financial markets where high risk investments may also generate high returns. Similarly, the application of MVP in energy markets has produced distinctive results and clearer cost risk trade-offs when renewables were clearly more expensive than conventional technologies. As the costs of renewables have come down in recent years, the cost risk trade-off is likely to be much smaller.

When modelling the Indonesian context, levelised generation costs and cost risks calculated in the previous chapter are applied in the model. The model, developed specifically for this analysis, has the following specific features:

- Eighteen electricity production scenarios were constructed which are exogenous parameters used as inputs to the model. Each scenario represents a portfolio containing a mix of renewable and fossil fuel generation technologies on the national level. There are three reference scenarios with electricity production targets and respective supply mix shares for 2025, 2035 and 2050 based on projections in the RUPTL and RUEN. Fifteen additional scenarios were constructed that deviate from these reference scenarios by assuming different supply mix shares, varying from scenarios containing larger and smaller shares of renewables to scenarios that added energy efficiency and carbon price assumptions (see Sections 7.3 and 7.4).
- Cost data on each technology—each of these scenarios contain the LCOEs and cost risks calculated in the previous chapter. However, some of the high-cost technologies such as coal with carbon storage, concentrated solar power or offshore wind have not been included, as PLN statistics have not yet categorised them separately, and current capacities and production from these sources are still small.
- Under each scenario, the expected annual electricity production of renewable technologies are computed from random realisations of output by technology, normally distributed with variance based on observed variability in historical output, capital/construction and fuel cost data.
- Under each scenario, the expected annual electricity production from fossil fuel–based technologies are computed from random realisations of output by technology as the residual to meet total assumed electricity demand under each scenario.
- Carbon emissions factors are included in the expected generation projections, allowing the model to calculate carbon emissions and costs associated with coal-, gas- and oil-based generation.
- Each scenario is calculated with and without a carbon price. Carbon prices are assumed to be US$25/tCO2 in 2025, rising five per cent per annum to US$41/tCO2

in 2035 and US$85/tCO2 in 2050. From a cost risk perspective, CO2 emissions represent long-term social costs associated with fossil fuels. Those costs could be factored in by PLN by putting a carbon market price on those emissions, thus changing the relative cost risks between fossil fuels and renewables.

- Cost data on each technology. Some of the high-cost technologies such as coal with carbon storage, concentrated solar power, or offshore wind have not been included, as PLN statistics have not yet categorised them separately, and as current capacities and production from these sources are still small.
- The model is implemented for numerical simulations using a Monte Carlo sampling approach. All stochastic variables are distributed normally and truncated at zero (to avoid random realisations with negative costs or negative amounts of generation). For each of the scenarios, 100,000 random realisations of the model are computed, for which averages and standard deviations are reported below.

7.3 Reference scenarios

Tables A1–A4 in Appendix 7.1 provide further details about the scenarios discussed below.

7.3.1 Existing generation capacity in 2016

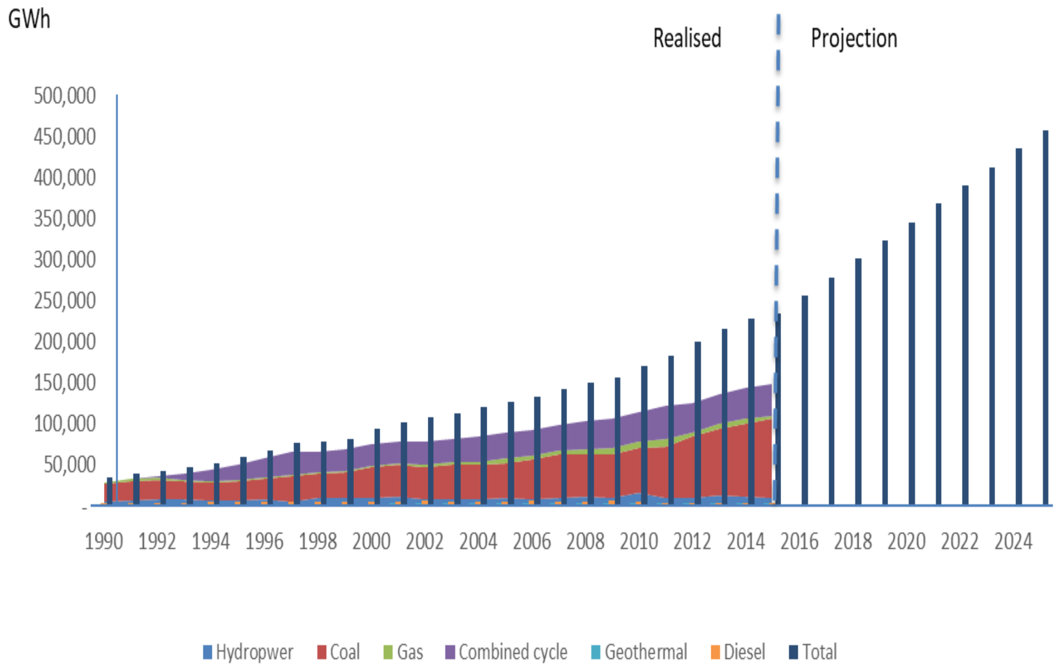
For 2016, electricity production is assumed to be at 234 TWh (PLN 2015).[124] The supply mix is 10 per cent renewable and 90 per cent fossil fuel–based electricity (PLN Statistics 2015). Coal-fired (135TWh or 54 per cent of total production) and gas-fired plants (50 TWh or 22 per cent) supply the bulk of this.

7.3.2 2025 scenario

PLN devises electricity demand and supply scenarios for a period of nine years in its annual RUPTL. In its latest scenarios, the utility aims to increase electricity generation by an additional 223 TWh to reach 457 TWh in 2025. This would require the annual addition of almost 25TWh per year or 7.7 per cent annual average growth.

[124] PLN issues annual nine-year business plans, the RUPTL. The latest projection is for 2016–2025, for which data in 2015 were used.

Figure 7.2: Realised and projected power production (1990–2025)



Source: PLN (2016b) and author's own calculations

The scenarios in the RUPTL 2016–2025 do not provide a breakdown into various generation technologies. The document states that PLN aims to achieve a 19 per cent share of renewable power in the power generation mix by 2025 (PLN 2016, p. 161). This would pose a significant increase compared to the existing mix of 10 per cent renewables and 90 per cent of fossil fuel–based generation. To achieve the targeted energy production mix of 19 per cent renewables and 81 per cent fossil fuel, here it is assumed that renewable generation would make up 28 per cent of the *required additional* generation in 2016–2025, while fossil fuel–based generation would make up the remaining 72 per cent (see Table A1 in Appendix 7.1).

7.3.3 2035 scenario

No specific production targets for 2035 were issued by the government, but the RUEN assumes an annual average growth rate of 7.9 per cent in energy production in 2025–2035, which would result in a 2035 total energy output of 951,258 GWh. This would mean an additional generation of 494,258 GWh in 2025–2035. No specific targets under each generation technology is given. In the present thesis, it is assumed that under the BAU scenario, coal remains the largest source of additional power generation at (46 per cent) with the geothermal share second at 15 per cent. The overall generation mix would be 28 per cent renewables and 72 per cent fossil fuel in 2035.

7.3.4 2050 scenario

The RUEN projects an energy output of 2,349,100 GWh in 2050, with the share of renewables in the energy mix at a minimum of 31 per cent. This means an added production of 494,258 GWh between 2035 and 2050. Under the BAU scenario, a share of 31 per cent of renewables in the total mix is assumed, which is the official minimum target for renewables in the RUEN. Key features are summarised in Table 7.1.

Table 7.1: Reference scenarios

Technology portfolio in year	2016	2025	2035	2050
Production capacity (TWh)	234	457	951	2,349
Share of renewables in total generation (%)	10	19	28	31
Share of renewables in added generation (%)	-	28	32	33

7.4 Portfolio modelling scenarios

This section describes the generation mix scenarios which are used to apply the portfolio model. The model provides numerical simulations that compare the cost risk effects of various supply scenarios that deviate from the official PLN documents. In total, there are 18 scenarios.

First, there are the three reference scenarios described in the previous section.

Second, the author constructed two versions of the reference scenarios, namely Strong Renewables (SR) and Weak Renewables (WR). The SR version adds more renewables into the generation mix under each of the reference scenarios, while the WR version reduces them. This results in six additional scenarios. Under each of the additional scenarios, the production targets of the reference scenarios remain unchanged. This means that the share of renewables and fossil fuel generation technologies in added generation are changed, which in turn changes the respective shares in the total mix.

Third, the author modelled a higher energy efficiency version for all these nine scenarios, resulting in nine additional scenarios. Adopting higher energy efficiency targets means lowering energy demand. Reduced demand translates into less electricity output produced across the various generation technologies.

7.4.1 Strong renewables portfolio

Three SR portfolio scenarios were modelled by modifying the three reference and BAU scenarios described in the previous section. All three SRs increase RE and commensurately less fossil fuel–based generation, especially through aggressive expansion of hydro, solar and geothermal. Added and total generation figures remain the same as in the reference scenarios, only the composition of the share in added generation were altered (i.e., more renewables were added on, and less fossil fuel–based generation (primarily coal) was produced). Tables 7.7–7.9 show a detailed breakdown of the shares. The key changes to the reference scenarios can be seen in Table 7.2.

Table 7.2: Strong renewables scenarios

Scenarios	2016	2025	2035	2050
Strong Renewables portfolio scenario				
Production capacity (TWh)	234	457	951	2,349
Share of renewables in total generation (%)	10	41	55	55
Share of renewables in added generation (%)	-	73	83	73

7.4.2 Weak renewables scenario

The scenarios assume a reduced expansion of renewables and an even more aggressive increase of coal-fired power generation. The reduction of renewables is mainly achieved by significantly reducing the shares of geothermal and hydropower. The total generation target under each of the reference scenarios are unchanged with only the composition of added generation altered (see Tables 7.3 and 7.7–7.9).

Table 7.3: Weak renewables scenarios

Weak Renewables portfolio scenario	2016	2025	2035	2050
Production capacity (TWh)	234	457	951	2,349
Share of renewables in total generation (%)	10	11	18	19
Share of renewables in added generation (%)	-	12	12	12

7.4.3 Demand side scenarios: Increased energy efficiency reduces production

On the demand side, adopting higher energy efficiency measures can result in lower energy demand and production. The Indonesian Government has stated an energy conservation target of 17 per cent by 2025 for the industrial sector in its Energy Conservation Master Plan (Rencana Induk Konservasi Energi Nasional) (ADB 2015, pp. 19–21). In the following section, additional energy efficiency scenarios are presented, in which the total production targets of the BAU, reference, SR and WR scenarios are reduced by 17 per cent, with shares of the reduced outputs allocated among individual generation technologies (see Table 7.4). Thus, the model does not detail specific energy conservation measures such as the application of energy efficient technologies in specific industries or the adoption of green building practices. These policies are implied when assuming a reduction in total demand and energy output. The scenarios have the following key features:

- In all three reference scenarios, the 17 per cent energy efficiency target is modelled entirely as a 17 per cent reduction in coal-fired generation output.
- In the three SR scenarios, the 17 per cent energy efficiency target is modelled as a 17 per cent reduction in coal-fired, gas-fired and geothermal generation output. In the 2025 scenario, coal-fired generation is reduced by 10 per cent and combined cycle–based generation by seven per cent. In the 2035 scenario, the respective reductions are 10 per cent for coal, one per cent for gas, four per cent for combined cycle and two per cent for geothermal. In the 2050 scenario, coal is reduced by 10 per cent and combined cycle by seven per cent.
- In the WR scenarios, the 17 per cent energy efficiency target is modelled as a 17 per cent reduction in coal-fired generation.
- Total generation output in all nine scenarios are reduced by 17 per cent, equivalent to the 17 per cent increase in energy efficiency.

Table 7.4: Demand side scenarios

Scenario	2016	2025	2035	2050
Reference scenarios plus higher energy efficiency				
Production capacity (TWh)	234	419	867	2,112
Share of renewables in total generation (%)	10	21	31	35
Share of renewables in added generation (%)	-	34	39	40
Strong renewables scenarios plus higher energy efficiency				
Production capacity (TWh)	234	419	867	2,112
Share of renewables in total generation (%)	10	45	98	88
Share of renewables in added generation (%t)	-	88	59	61
Weak renewables scenarios plus higher energy efficiency				
Production capacity (TWh)	234	419	867	2,112
Share of renewables in total generation (%)	10	12	20	21
Share of renewables in added generation (%)	-	14	14	14

Figures 7.3–7.5 provide graphical overviews of the portfolio scenarios involved. In absolute numbers, coal is the biggest driver in all scenarios, including in the SR portfolios, as coal-based generation provides already a large base of existing and planned generation.

Figure 7.3: 2025 electrical production scenario (GWh)

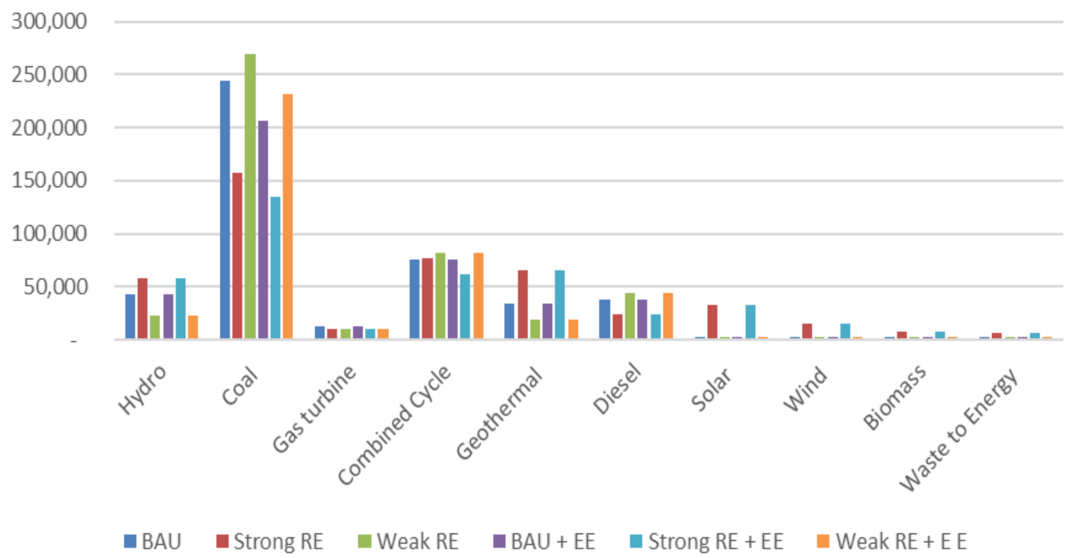


Figure 7.4: 2025 electrical production scenario (GWh)

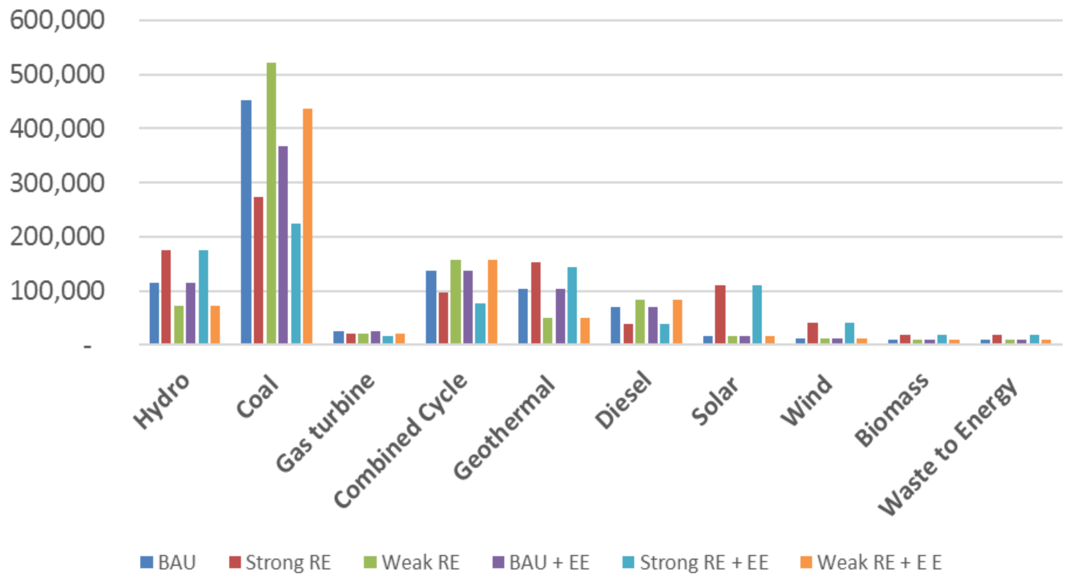
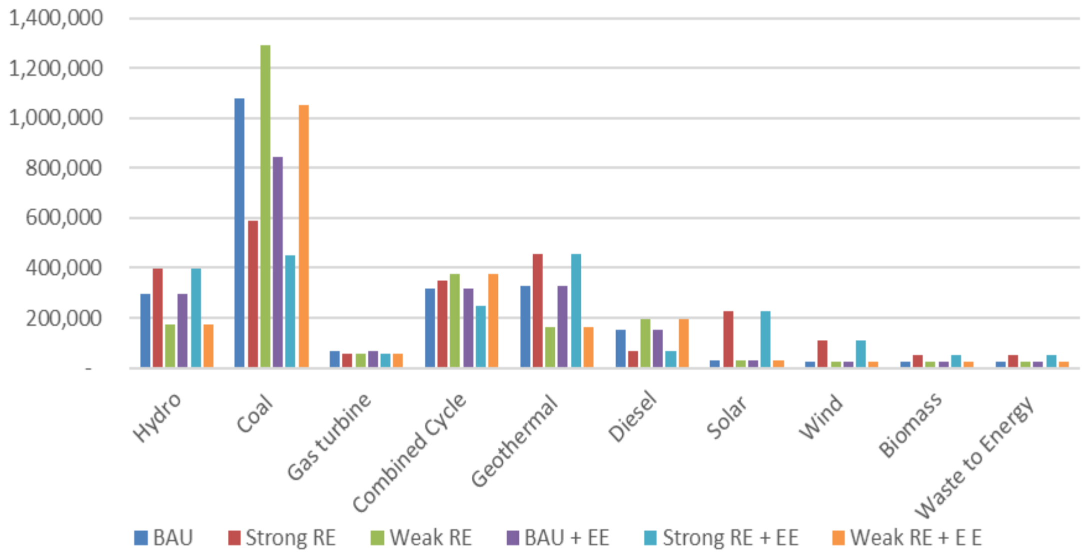
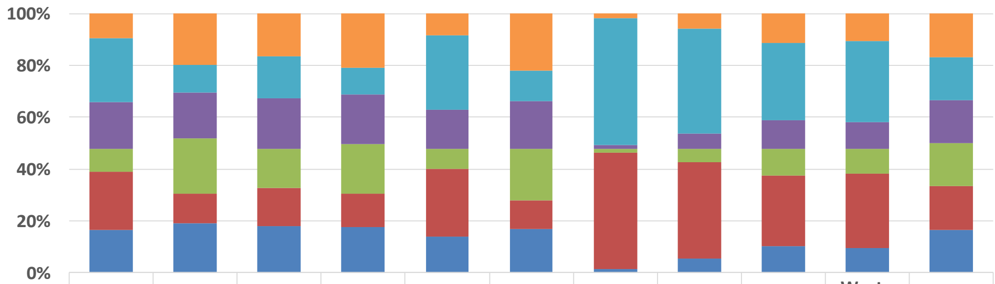


Figure 7.5: 2025 electrical production scenario (GWh)



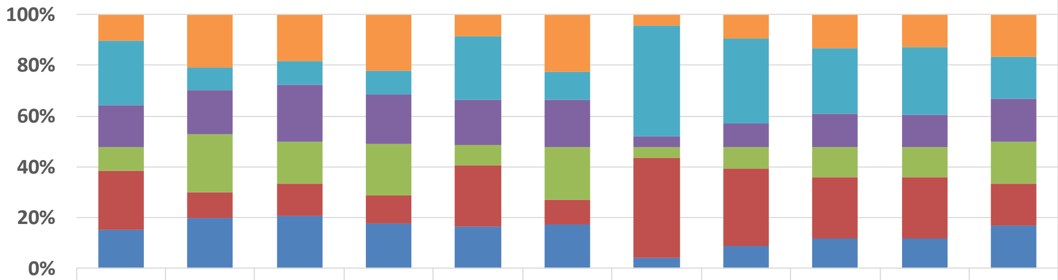
Figures 7.6–7.8 provide the corresponding shares of renewables and fossil fuel–based energy production in the portfolios.

Figure 7.6: 2025 scenarios (% share of generation technologies)



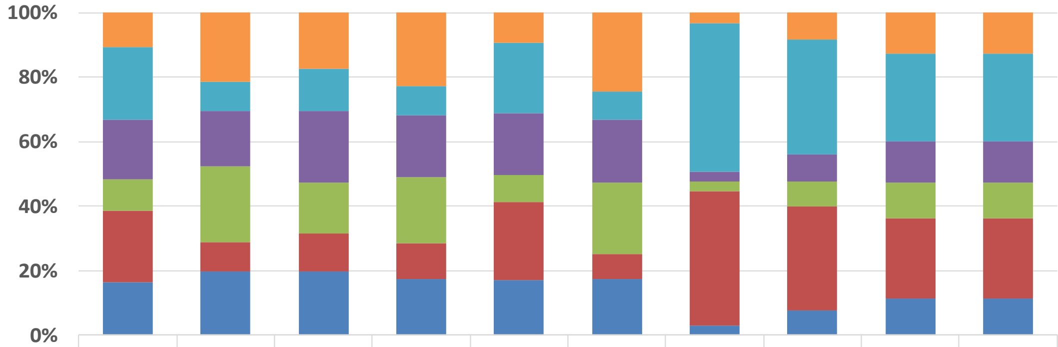
	Hydro	Coal	Gas turbine	Combined Cycle	Geothermal	Diesel	Solar	Wind	Biomass	Waste to Energy	Total
Weak RE + E E	5%	55%	3%	20%	5%	11%	1%	1%	1%	1%	100%
Strong RE + EE	14%	30%	3%	9%	16%	6%	16%	4%	2%	2%	100%
BAU + EE	10%	49%	3%	18%	8%	9%	1%	1%	1%	1%	100%
Weak RE	5%	59%	2%	18%	4%	10%	0%	0%	1%	0%	100%
Strong RE	13%	32%	2%	12%	14%	5%	15%	3%	2%	1%	100%
BAU	9%	54%	3%	16%	8%	8%	0%	0%	1%	0%	100%

Figure 7.7: 2035 scenarios (% share of generation technologies)



	Hydro	Coal	Gas turbine	Combined Cycle	Geothermal	Diesel	Solar	Wind	Biomass	Waste to Energy	Total
Weak RE + E E	8%	50%	2%	18%	6%	10%	2%	1%	1%	1%	100%
Strong RE + EE	20%	22%	1%	8%	17%	5%	18%	5%	2%	2%	100%
BAU + EE	13%	42%	3%	16%	12%	8%	2%	1%	1%	1%	100%
Weak RE	8%	55%	2%	17%	5%	9%	2%	1%	1%	1%	100%
Strong RE	18%	25%	2%	9%	16%	4%	17%	4%	2%	2%	100%
BAU	12%	47%	3%	14%	11%	7%	2%	1%	1%	1%	100%

Figure 7.8: 2050 scenarios (% share of generation technologies)



	Hydro	Coal	Gas turbine	Combined Cycle	Geothermal	Diesel	Solar	Wind	Biomass	Waste to Energy
Weak RE + E E	8%	50%	3%	18%	8%	9%	1%	1%	1%	1%
Strong RE + EE	17%	22%	2%	7%	18%	3%	21%	5%	2%	2%
BAU + EE	14%	40%	3%	15%	16%	7%	1%	1%	1%	1%
Weak RE	7%	55%	2%	16%	7%	8%	1%	1%	1%	1%
Strong RE	17%	22%	2%	9%	20%	3%	19%	5%	2%	2%
BAU	13%	46%	3%	14%	14%	7%	1%	1%	1%	1%

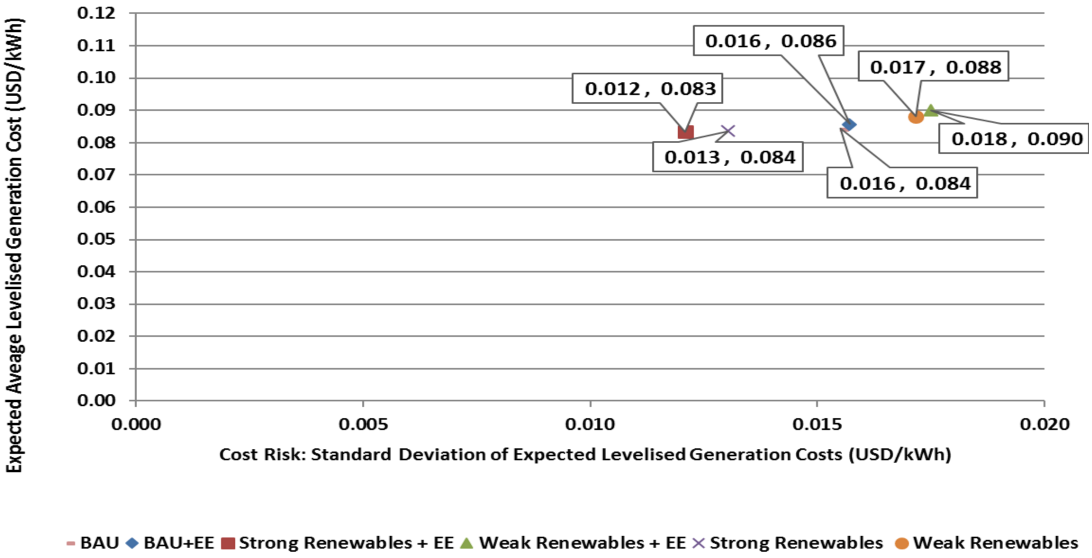
7.5 Portfolio modelling results

7.5.1 Comparison of portfolios across all scenarios at seven per cent

In all scenarios, costs across renewable and fossil fuel technologies move within a narrow range. RE scenarios combined with energy efficiency are cheaper and show lower cost risk levels (see Figures 7.9–7.11).

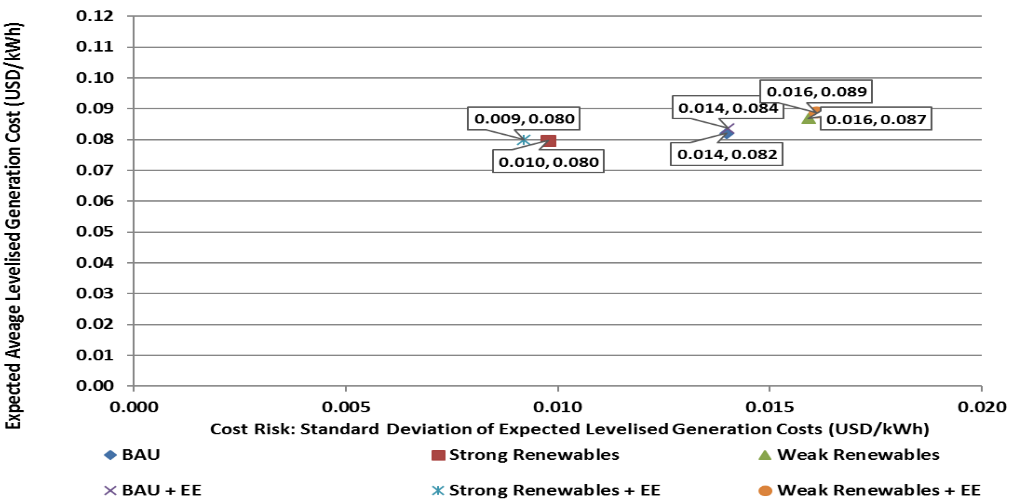
In the 2025 scenario, the SR plus energy efficiency scenario is the one with the lowest expected average cost and cost risk levels at 8.3 and 1.2 cents/kWh respectively. In contrast, the WR plus energy efficiency scenario shows the highest levels of expected cost at 9 and 1.7 cents/kWh respectively (see Figure 7.9).

Figure 7.9: 2025 scenarios at seven per cent discount rate



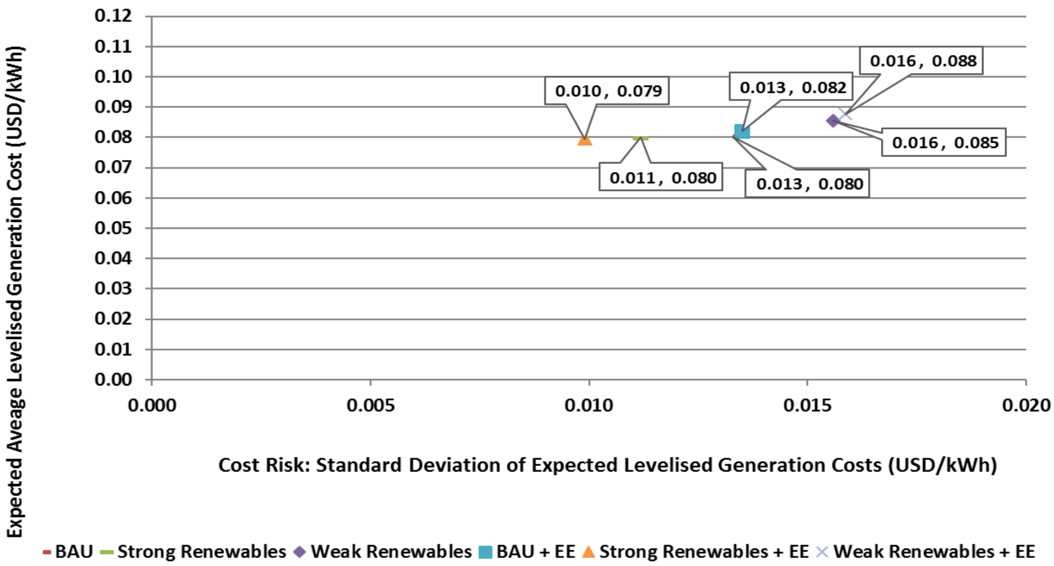
In the 2035 scenarios, SR plus energy efficiency scenario also proves to be the optimal choice in terms of both low levels of cost and cost risk (8 cents/kWh and 1 cent/kWh), while the WR plus energy efficiency scenario shows the highest cost and cost risk levels (8.8 cents/kWh and 1.6 cents/kWh respectively).

Figure 7.10: 2035 scenarios at seven per cent discount rate



The 2050 scenarios show the same outcomes, with SR plus energy efficiency scenarios and the WR plus energy efficiency being at the polar opposite ends of the cost/cost risk spectrum.

Figure 7.11: 2050 scenarios at seven per cent discount rate



Overall, the SR scenario has the optimal balance between lowest average cost and lowest risk among all portfolios. This means that significantly increasing RE generation—mainly driven by geothermal, large hydropower and solar—will reduce both the average portfolio generation costs and the cost risk of the energy mix, based on the assumptions on costs and risk in this analysis (see Chapter 6). The strong expansion of renewables combined with energy efficiency measures is on par with the SR scenario, but has a slightly lower cost risk. This shows that added energy efficiency measures reduces risk of renewables even further. This can be explained by the fact that energy efficiency gains are translated into less electricity generation from coal-fired generation, which in turn reduces the overall cost risk of the portfolio.

Conversely, in 2025 the 'worst' scenario is the WR scenario which shows the highest average portfolio generation cost and the highest risk. Like in the case of the SR/SR plus energy efficiency case, the later scenarios in 2035 and 2050 make the WR plus energy efficiency scenario the least attractive option. This is because any gains of energy efficiency cannot dent the already high risks associated with the high share of coal in power generation in this scenario.

Overall, all technologies are within a narrow average cost range of 8–9 cents/kWh, and standard deviations/risks move also within a narrow margin of 1–1.7 cents/kWh across generation technologies.

7.5.2 Scenarios with a higher discount rate of 10 per cent

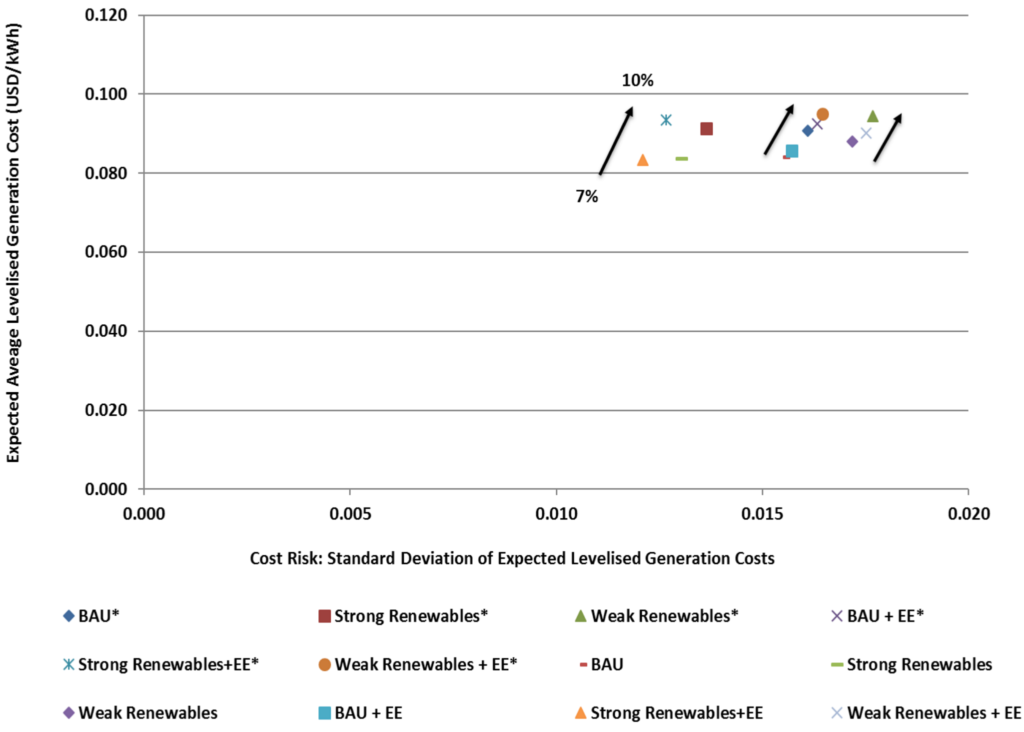
As discussed in Chapter 6, interest rates and required rates of return influence investment decision-making greatly. In this analysis, annual real interest rates for the computation of LCOEs are assumed to be between three and 10 per cent in Indonesia, with seven per cent per annum representing the average lending rate in 2015–2016 (Chapter 6). Private sector perception puts a relatively higher risk premium in Indonesia, and it is not unusual that developers require IRRs at 10 per cent per annum or more to plan project financing.

When applying a 10 per cent per annum discount rate in the scenarios, the average cost for all portfolios becomes higher, including SR (see Figures 7.12–7.14). In fact, the BAU portfolio shows the lowest average levelised cost at 10 per cent per annum, with all other technologies are almost on par across all scenarios, with the WR plus energy efficiency scenario the costliest option.

Risk levels do not change much, with SR plus energy efficiency portfolio remaining the least risky option.

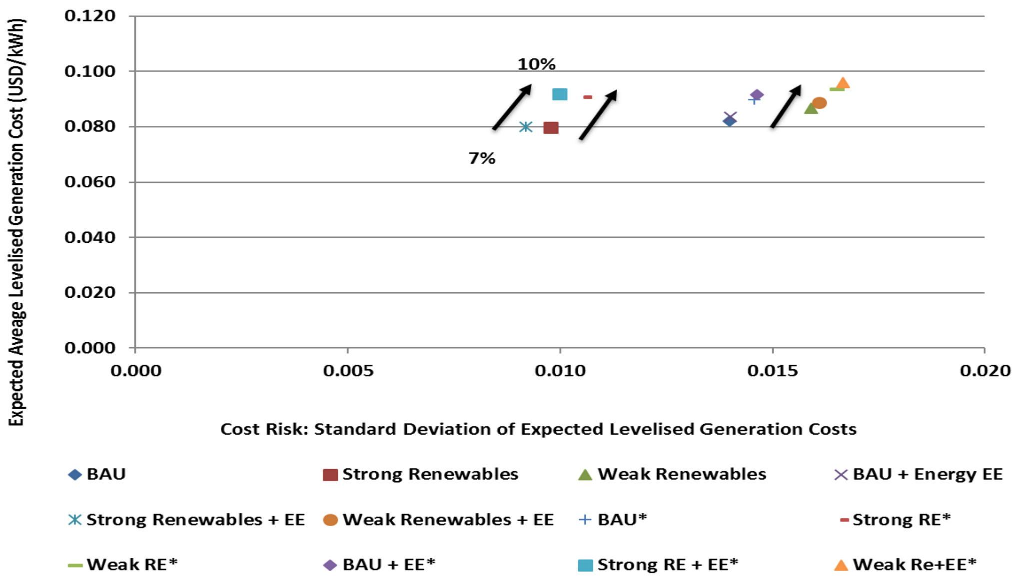
Overall, a higher discount rate makes renewables a less attractive option in terms of average levelised costs, but they remain the best option in terms of lower risk levels compared to non-renewables.

Figure 7.12: 2025 scenarios at seven and 10 per cent discount rates



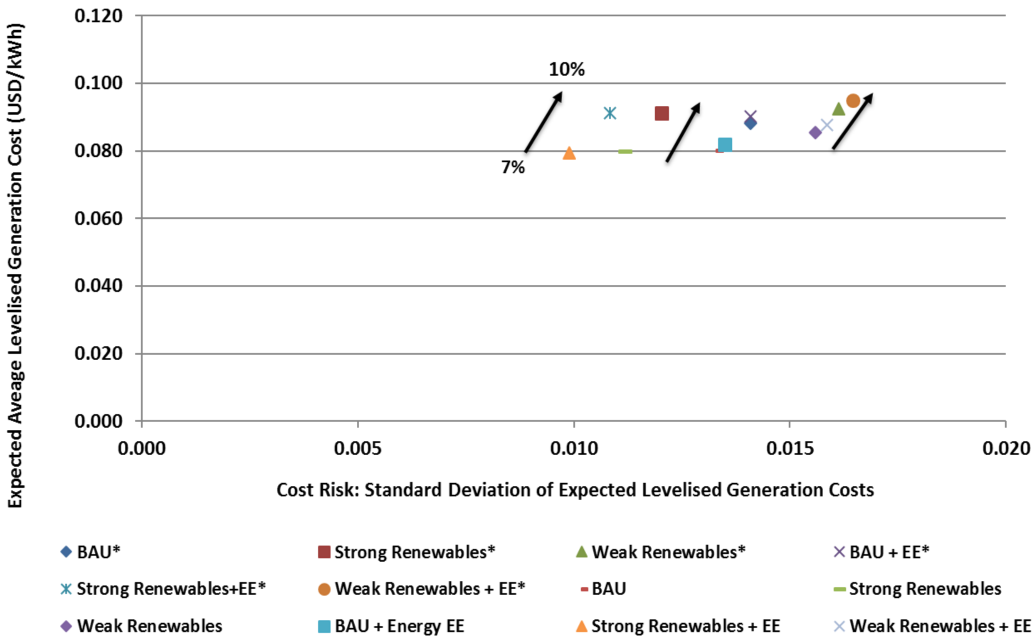
Notes: * 10 per cent discount rate. EE = energy efficiency.
Source: Author's calculations based on data in Tables A1–A3 in Appendix 7.1.

Figure 7.13: 2035 scenarios at seven and 10 per cent discount rates



Notes: * 10 per cent discount rate. EE = energy efficiency.
Source: Author's calculations based on data in Tables A1–A3 in Appendix 7.1.

Figure 7.14: 2050 scenarios at seven and 10 per cent discount rates

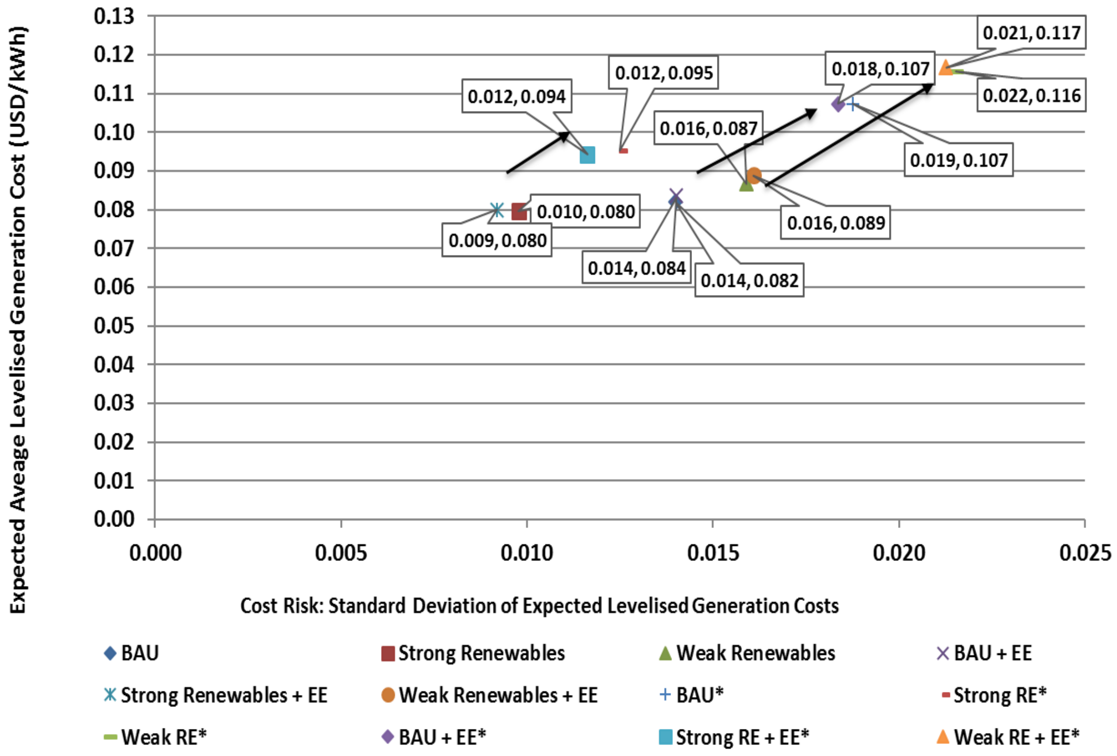


Notes: * 10 per cent discount rate. EE = energy efficiency.
Source: Author's calculations based on data in Tables A1–A3 in Appendix 7.1.

7.5.3 Scenarios with carbon prices

As explained in the previous chapter, CO2 emissions represent cost risks, as they are long-term social costs associated with fossil fuels. A carbon price provides a market signal and an incentive to switch to renewables. The model assumes a carbon price of US$25/tCO2 in 2025, which increases annually by five per cent, reaching US$41/tCO2 in 2035 and US$85/tCO2 in 2050. When carbon prices and emission costs are added, then costs across all scenarios average portfolio increase more for fossil fuel–based ones compared to renewables. Figure 7.15 shows the 2035 scenario only, but the general pattern holds for the other reference scenarios.

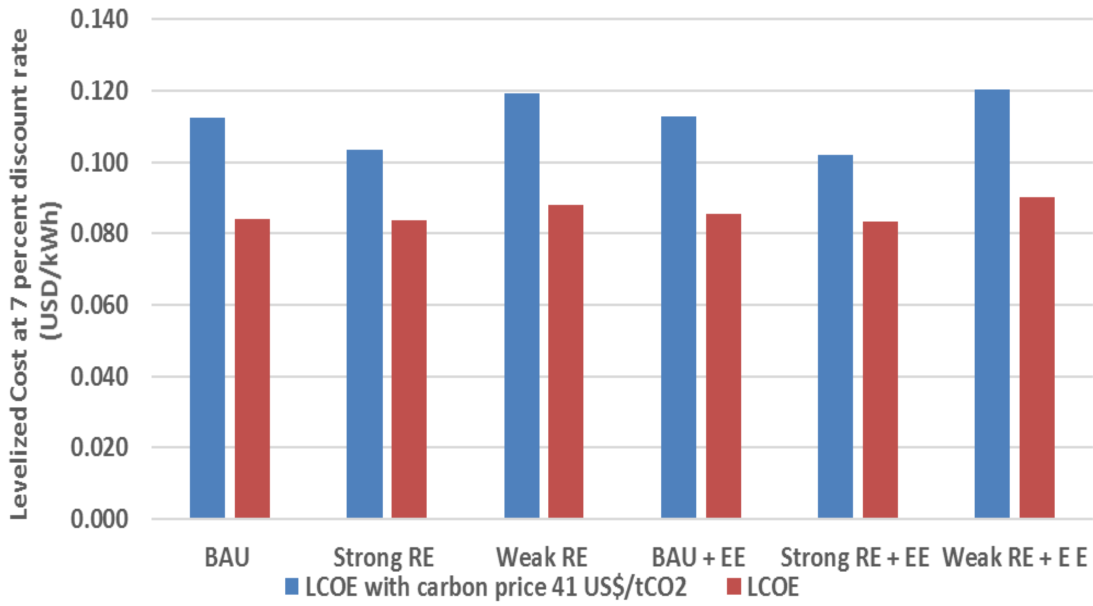
Figure 7.15: 2035 scenario at seven per cent discount rate and US$41/tCO2



At seven per cent and with a carbon price of US$41/tCO2, the increase in average portfolio generation cost is pronounced for the BAU and WR scenarios. The former increases by 31 per cent from 8.2 to 10.7 cents/kWh, while the latter increases by 33 per cent from 8.7 to 11.6 cents/kWh. SR and SR plus energy efficiency scenarios do increase at around 20 per cent from 8 to 9.5 cents/kWh (see Tables A1–A3 in Appendix 7.1). Portfolio risks do also increase for all generation portfolios, with WR and WR plus energy efficiency scenarios showing the largest risk in portfolio risk.

It should be noted that much of the increase in costs is simply a transfer in the form of tax revenues. Thus, the underlying cost of electricity generation changes only within a relatively narrow band of between 8.3–12.1 cents/kWh across the various technologies, if we compare the average LCOEs with and without carbon costs across all scenarios (see Figure 7.16).

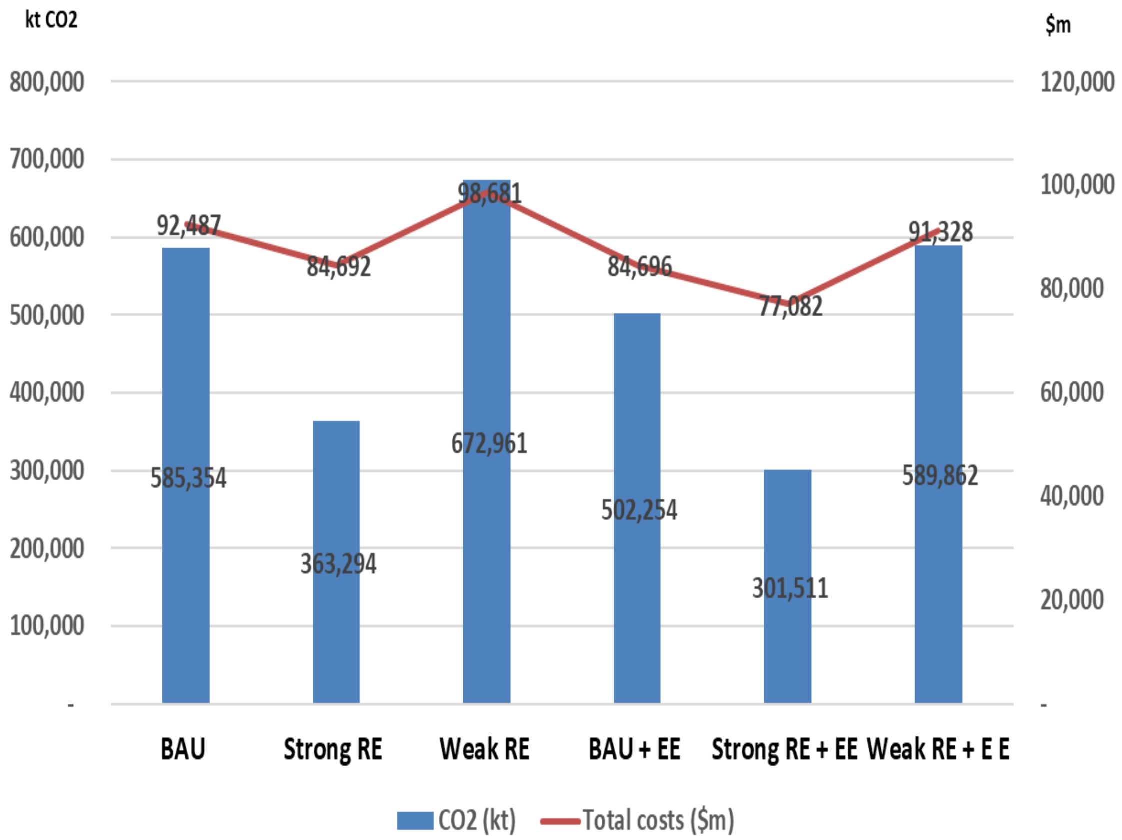
Figure 7.16: Levelised cost with and without carbon costs at seven per cent discount rate



When increasing the discount rate to 10 per cent, the average levelised generation cost increases further for all portfolios, with the WR plus energy efficiency scenarios again showing the highest costs. Portfolio risks do increase across all technologies, albeit in a less pronounced way compared to the increase in costs when the carbon price is applied (see Tables A1–A3 in Appendix 7.1).

The scenarios include CO2 emissions and costs in terms of carbon tax value. For the 2035 scenario, Figure 7.17 shows that the highest emissions are produced in the WR scenario, with its high share of coal-powered generation (55 per cent) in the production mix (see Tables A1–A3 in Appendix 7.1). The carbon tax value of the WR Scenario amounts to US$98 billion. This is a relatively large amount owing to the high carbon price assumption of US$41/tCO2, especially given that the current price range across various national carbon markets is between US$4–22 (World Bank 2016, p. 12). Lowest emissions are incurred in the SR plus energy efficiency scenario, which is due to the low share of coal (26 per cent) and the high share of renewables (59 per cent in the total mix).

Figure 7.17: 2035 CO2 emissions and costs



7.5.4 Scenario with more aggressive solar power expansion

As discussed in Chapter 6, solar power generation costs have declined massively in recent years. Despite current regulatory and policy barriers to solar PV development and the very small share of solar in the present energy mix in Indonesia, it is reasonable to assume that global declining prices will make solar power an increasingly attractive option for PLN. An additional scenario is introduced which increases the share of solar power and assumes that the LCOE for solar power is far lower than in the standard scenarios. To simplify assumptions, variations of solar power technologies, such as community or independent systems are ignored here. Specifically, the scenarios include:

- The share of solar power is increased in the SR and SR plus Energy Efficiency (SREE) portfolios in each scenario.
- In the SR portfolios, the share of solar in 2025 is increased to 15 per cent, in 2035 to 17 per cent, and in 2050 to 19 per cent of the power mix.
- In the SREE, the share of solar in 2025 is increased to 16 per cent, in 2035 to 18 per cent and in 2050 to 21 per cent (see Table 7.5)

- The LCOE for solar power is reduced from 11 cents/kWh to less than half at 5 cents/kWh at seven per cent and from 14–11 cents/kWh at 10 per cent.

Table 7.5: Scenarios with added solar power

Scenarios	2025	2035	2050
Reference scenarios			
Solar production capacity (TWh)	2	16	30
Share of renewables in total generation (%)	19	28	31
Share of solar power in total generation (%)	0	2	1
Weak Renewables scenario			
Solar production capacity (TWh)	2	16	30
Share of renewables in total generation (%)	11	18	19
Share of solar power in total generation (%)	0	2	1
Strong Renewables scenario			
Solar production capacity (TWh)	67	159	435
Share of renewables in total generation (%)	41	55	55
Share of solar power in total generation (%)	15	17	19
Reference scenarios plus higher energy efficiency			
Solar production capacity (TWh)	2	16	30
Share of renewables in total generation (%)	21	31	35
Share of solar power in total generation (%)	1	2	1
Strong Renewables scenarios plus higher energy efficiency			
Solar production capacity (TWh)	66	159	435
Share of renewables in total generation (%)	45	98	88
Share of solar power in total generation (%)	16	18	21
Weak Renewables scenarios plus higher energy efficiency			
Solar production capacity (TWh)	2	16	30
Share of renewables in total generation (%)	12	20	21
Share of solar power in total generation (%)	1	2	1

The impacts are illustrated in Table A4 in Appendix 7.1.

With the seven per cent discount rate, generation costs and risks decline most strongly in the SR and SREE portfolios in all scenarios. Declining costs and risks are most pronounced for the 2025 scenario: costs decline by 0.4 cents/kWh and cost risks by 1.2 cents/kWh when compared to the original scenario. The SR and SREE portfolios remain the optimal choices in terms of the smallest average costs and risks. The other portfolios see a slight reduction in their portfolio risks in 2025, but almost no changes in the 2035 and 2050 scenarios (see Table A4 in Appendix 7.1).

With carbon prices, the changes are similar, with slightly stronger cost and risk reduction effects for the SR and SREE portfolios, but with more ambiguous effects for the other portfolios. Cost reductions and cost risk reductions are especially strong in the 2050 SR and SREE portfolios: Costs decline by 0.6–0.8 cents/kWh, while cost risks decline by 2.2–2.5 cents/kWh (see Table A4 in Appendix 7.1).

7.6 Discussion and summary

The broad picture emerging from the analysis is that the stochastic portfolio simulations result in small cost effects, but in significant differences in risks across the various portfolio scenarios. Portfolios with a relatively large share of RE generation and combined with higher energy efficiency outcomes represent the most efficient portfolios as they optimise cost and risk minimisation. Conversely, portfolios with a small share of renewables and commensurately higher share of fossil fuel–based electricity generation present the costlier and riskier options.

A higher discount rate at 10 per cent does not change the risk profiles significantly, but pushes costs slightly higher for all portfolios, especially those containing more renewables.

Adding carbon prices increases the costs for all portfolios but is more pronounced for those portfolios with a high share of fossil fuel–based technologies. Finally, an increase in the share of solar power technologies combined with lower LCOEs further reduces the costs and risks, especially in the SR scenario portfolio.

The lower risk profile for individual renewable technologies, mainly due to the absence of fuel price risks, decreases risks for a portfolio containing more renewables.

Conversely, higher standard deviation of average levelised costs of individual fossil fuel–based technologies push up cost risk levels of fossil fuel–dominated portfolios.

The relatively small differences in average levelised generation costs across the portfolios are determined by the estimated LCOEs for the individual technologies. Some of the high-cost technologies such as coal with carbon storage, concentrated solar power or offshore wind have not been included in the present analysis, as PLN statistics have not yet categorised them separately in the generation capacity and production figures. Thus, the LCOEs across the technologies used in the MVP analysis show a narrow cost range.

The results of the MVP analysis also point to the important role interest rates play in influencing cost and risk outcomes. Higher rates push expected costs up for renewables, as they do influence capital risks of capital-intensive renewables such as large hydropower, geothermal and solar power.

How do these results compare to similar studies? Models combining MVP analysis with stochastic simulation have not been applied to Indonesia's electricity market, so direct comparisons are not possible. Studies in other countries have largely focused on advanced economies in Europe (Bazilian & Roques 2008; Ioannou, Angus & Brennan 2017) and small developing economies (Dornan & Jotzo 2015).

In terms of risk mitigation effects, the results of those studies are broadly in line with the results of the MVP analysis employed in this thesis. Increased portfolio diversification has reduced overall costs and risks on planning scenarios for the European Union as a whole and in individual country case studies including the Netherlands, Ireland and Scotland (Bazilian & Roques 2008). Dornan and Jotzo (2015) applied a stochastic simulation model to Fiji's electricity grid to assess the risk mitigation effects of renewables. The results showed that investments in low-cost, low-risk renewable technologies, including geothermal, energy efficiency, biomass and bagasse technologies, are expected to lower both generation costs and financial risk for the electricity grid in Fiji.

However, these studies were conducted in the 2000s when most renewables were more expensive than fossil fuels on a standalone cost basis. As mentioned earlier, the cost of solar and wind power has been reduced drastically in recent years, making the case for including more renewables in energy generation portfolios even more attractive. Moreover, the case studies of the European Union countries also included nuclear technologies in the mix, whereas the model applied in this thesis does not. The results of the model applied by Dornan and Jotzo (2015) were also driven mainly by the reduction in investment into oil-fired generation, whereas the Indonesian case emphasises the role in coal and gas-fired technologies.

Some important caveats and limitation need to be considered in drawing conclusions from this analysis and point to avenues for further research. First, portfolio analysis is about the interaction between LCOEs and standard deviations of costs, but the data for costs of future electricity generation in Indonesia are limited and not necessarily reliable, so assumptions need to be used to illustrate possible effects. Project-specific data from the Indonesian electricity sector are not widely available and this research has relied mainly on 'benchmarking' international power plant cost data for the Indonesian context.

Second, standard deviations to approximate risks have also been mainly taken from the international literature, thus possibly underestimating risk differences across technologies. For example, capital (construction) risks between large and small renewables or large renewables and coal should potentially be more pronounced.

Third, this analysis has not taken account of possible correlation between costs of the various technologies. Incorporating correlations would alter the modelling results for the risk profile of several technologies.

Fourth, some risks faced by renewables are not included in the model. These include intermittency, storage and grid service costs and concerns about a reliable supply chain for spare parts and limited local human resources capacity to manage RE systems.

Fifth, scenarios using PLN's RUPTL limit the scope of the MVP analysis in various aspects. One limitation is that the RUPTL is revised on an annual basis, so the cost risks might change significantly from year to year, as generation expansion plans are adjusted to minimise the risk of oversupply. Moreover, the scenarios are limited to the national level and ignore scenarios affecting regional grids. Regional cost structures differ, as RE resources such as geothermal and hydropower are not equally distributed across Indonesia. Finally, differences in the economic structures also influence energy demand.

Sixth, portfolio analysis is very insightful in showing clear choices in financial markets where high risk investments may also generate high returns. Similarly, the application of MVP in energy markets has produced distinctive results and clearer cost risk trade-offs when renewables were clearly more expensive than conventional technologies. As the costs of renewables have come down in recent years, the cost risk trade-off is relatively small, as results for the model has shown in the Indonesian case. Nevertheless, the MVP analysis presented here provides important and, in many respects, novel insights.

7.7 Conclusion

This chapter applied MVP theory to show the effects of diversifying the electricity supply mix in the system. The MVP framework provides a cost risk analysis of various long-term portfolios comprising of a mix of renewable and 'brown' generation technologies. Portfolio scenarios for 2025, 2035 and 2050 are evaluated based on electricity production assumptions of government planning documents such as the RUPTL and RUEN.

The MVP analysis shows that cost effects are relatively small, but the difference in risks across the generation technologies is significant. Portfolios with SR and combined with higher energy efficiency outcomes represent the most efficient baskets, as they optimise cost and risk minimisation. Conversely, portfolios with a small share of renewables present the costlier and riskier options. A higher discount rate at 10 per cent does not change the risk profiles significantly, but pushes costs slightly higher for all portfolios, including those containing more renewables. Adding carbon prices increases the risks and costs for all portfolios, in a way that is more pronounced for those portfolios with a high share of fossil fuel–based technologies. Finally, an increase in the share of solar power technologies combined with lower LCOEs further reduces the costs and risks of the portfolios containing a large share of renewables.

The high cost risks associated with large geothermal and hydropower projects suggest that fiscal policies to reduce capital and construction risks could make large-scale hydropower and geothermal projects more feasible. For example, the government could provide tax exemptions for importing renewable technologies or generally make sure that there are no import barriers. De-risking large geothermal and hydropower projects could also take the form of providing risk guarantees and improving land acquisition policies. Finally, the government’s ongoing reform to reduce fuel subsidies and introduce cost-reflective electricity tariffs has a direct impact on PLN’s finances and might lessen the utility’s hard budget constraint to invest in renewables.

Appendix 7.1: Quantitative portfolio modelling scenarios

Table A1: 2025 portfolio modelling scenarios and results

					2025							shares (%)		
GWh	2016	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E	2016	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E
Hydro	13,740	42,732	58,343	22,661	42,732	58,343	22,661	0.06	0.09	0.13	0.05	0.10	0.14	0.05
Coal	135,281	244,557	157,582	269,088	206,645	135,281	231,176	0.58	0.54	0.34	0.59	0.49	0.32	0.55
Gas turbine	6,337	13,027	10,797	10,797	13,027	10,797	10,797	0.03	0.03	0.02	0.02	0.03	0.03	0.03
Combined Cycle	44,036	75,257	77,487	81,947	75,257	61,876	81,947	0.19	0.16	0.17	0.18	0.18	0.15	0.20
Geothermal	10,048	34,579	65,800	18,968	34,579	65,800	18,968	0.04	0.08	0.14	0.04	0.08	0.16	0.05
Diesel	24,050	37,431	24,050	44,121	37,431	24,050	44,121	0.10	0.08	0.05	0.10	0.09	0.06	0.11
Solar	19	2,249	33,470	2,249	2,249	33,470	2,249	0.00	0.00	0.07	0.00	0.01	0.08	0.01
Wind	9	2,239	15,620	2,239	2,239	15,620	2,239	0.00	0.00	0.03	0.00	0.01	0.04	0.01
Biomass	437	2,667	7,127	2,667	2,667	7,127	2,667	0.00	0.01	0.02	0.01	0.01	0.02	0.01
Waste to Energy	32	2,262	6,722	2,262	2,262	6,722	2,262	0.00	0.00	0.01	0.00	0.01	0.02	0.01
Total	233,989	457,000	457,000	457,000	419,088	419,088	419,088	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Renewables	24,285	86,728	187,083	51,046	86,728	187,083	51,046	0.10	0.19	0.41	0.11	0.21	0.45	0.12
Fossil fuel	209,704	370,272	269,917	405,954	332,360	232,005	368,042	0.90	0.81	0.59	0.89	0.79	0.55	0.88
7% discount rate														
Standard deviation of levelised cost		0.016	0.013	0.017	0.016	0.012	0.018							
Expected levelised average cost (US$/kWh)		0.084	0.084	0.088	0.086	0.083	0.090							
- with carbon price at 25 US/tCO2:														
Standard deviation of levelised cost		0.018	0.014	0.020	0.018	0.013	0.020							
Expected levelised average cost (US$/kWh)		0.101	0.096	0.107	0.102	0.095	0.109							
10% discount rate														
Standard deviation of levelised cost		0.016	0.014	0.018	0.016	0.013	0.018							
Expected levelised average cost (US$/kWh)		0.091	0.093	0.094	0.093	0.093	0.096							
- with carbon price at 25 US/tCO2:														
Standard deviation of levelised cost		0.018	0.015	0.020	0.018	0.014	0.020							
Expected levelised average cost (US$/kWh)		0.108	0.105	0.113	0.109	0.105	0.115							

Notes: EE = energy efficiency. In the different scenarios, higher EE is equivalent to reduced energy demand, resulting in reduced generation. BAU plus 17% increase in EE = coal is reduced by 17% compared to BAU. Strong RE plus 17% higher EE = coal is reduced by 10%, combined cycle by 7% compared to Strong RE Scenario. Weak RE plus 17%. EE = coal-based generation is reduced by 17%.

Table A2: 2035 portfolio modelling scenarios and results

GWh				2035								shares (%)		
	2016	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E	2016	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E
Hydro	13,740	115,906	175,217	71,423	115,906	175,217	71,423	0.06	0.12	0.18	0.08	0.13	0.20	0.08
Coal	135,281	451,844	273,911	521,041	367,821	224,486	437,017	0.58	0.47	0.29	0.55	0.42	0.26	0.50
Gas turbine	6,337	25,625	20,683	20,683	25,625	15,740	20,683	0.03	0.03	0.02	0.02	0.03	0.02	0.02
Combined Cycle	44,036	137,281	97,740	157,051	137,281	77,970	157,051	0.19	0.14	0.10	0.17	0.16	0.09	0.18
Geothermal	10,048	104,257	153,683	49,889	104,257	143,798	49,889	0.04	0.11	0.16	0.05	0.12	0.17	0.06
Diesel	24,050	69,317	39,661	84,144	69,317	39,661	84,144	0.10	0.07	0.04	0.09	0.08	0.05	0.10
Solar	19	16,112	110,021	16,112	16,112	110,021	16,112	0.00	0.02	0.12	0.02	0.02	0.13	0.02
Wind	9	11,642	41,298	11,642	11,642	41,298	11,642	0.00	0.01	0.04	0.01	0.01	0.05	0.01
Biomass	437	9,840	19,725	9,840	9,840	19,725	9,840	0.00	0.01	0.02	0.01	0.01	0.02	0.01
Waste to Energy	32	9,435	19,320	9,435	9,435	19,320	9,435	0.00	0.01	0.02	0.01	0.01	0.02	0.01
Total	233,989	951,258	951,258	951,258	867,234	867,234	867,234	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Renewables	24,285	267,192	519,263	168,340	267,192	509,378	168,340	0.10	0.28	0.55	0.18	0.31	0.59	0.19
Fossil fuel	209,704	684,067	431,995	782,918	600,043	357,856	698,894	0.90	0.72	0.45	0.82	0.69	0.41	0.81
7% discount rate														
Standard deviation of levelised cost		0.014	0.010	0.016	0.014	0.009	0.016							
Expected levelised average cost (US$/kWh)		0.082	0.080	0.087	0.084	0.080	0.089							
with carbon price at 41 US/tCO2:														
Standard deviation of levelised cost		0.019	0.012	0.022	0.018	0.012	0.021							
Expected levelised average cost (US$/kWh)		0.107	0.095	0.116	0.107	0.094	0.117							
10% discount rate														
Standard deviation of levelised cost		0.015	0.011	0.017	0.015	0.010	0.017							
Expected levelised average cost (US$/kWh)		0.090	0.091	0.094	0.092	0.092	0.096							
with carbon price at 41 US/tCO2:														
Standard deviation of levelised cost		0.019	0.013	0.022	0.019	0.012	0.022							
Expected levelised average cost (US$/kWh)		0.115	0.107	0.123	0.115	0.106	0.124							

Notes: EE = energy efficiency. In the different scenarios, higher EE is equivalent to reduced energy demand, resulting in reduced generation. BAU plus 17% increase in EE = coal is reduced by 17% compared to BAU. Strong RE plus 17% higher EE = coal is reduced by 10%, gas by 1 %, combined cycle by 4% and geothermal by 2% compared to Strong RE scenario. Strong RE plus 17% higher EE = coal is reduced. Weak RE plus 17%. EE = coal-based generation is reduced by 17%.

Table A3: 2050 portfolio modelling scenarios and results

					2050							shares (%)		
GWh	2016	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E	2016	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E
Hydro	13,740	297,625	395,474	171,820	297,625	395,474	171,820	0.06	0.13	0.17	0.07	0.14	0.19	0.08
Coal	135,281	1,080,873	591,629	1,290,549	843,240	451,844	1,052,916	0.58	0.46	0.25	0.55	0.40	0.21	0.50
Gas turbine	6,337	67,560	53,582	53,582	67,560	53,582	53,582	0.03	0.03	0.02	0.02	0.03	0.03	0.03
Combined Cycle	44,036	319,000	346,957	374,914	319,000	249,108	374,914	0.19	0.14	0.15	0.16	0.15	0.12	0.18
Geothermal	10,048	327,912	453,718	160,171	327,912	453,718	160,171	0.04	0.14	0.19	0.07	0.16	0.21	0.08
Diesel	24,050	153,187	69,317	195,122	153,187	69,317	195,122	0.10	0.07	0.03	0.08	0.07	0.03	0.09
Solar	19	30,090	225,788	30,090	30,090	225,788	30,090	0.00	0.01	0.10	0.01	0.01	0.11	0.01
Wind	9	25,621	109,491	25,621	25,621	109,491	25,621	0.00	0.01	0.05	0.01	0.01	0.05	0.01
Biomass	437	23,818	51,775	23,818	23,818	51,775	23,818	0.00	0.01	0.02	0.01	0.01	0.02	0.01
Waste to Energy	32	23,413	51,370	23,413	23,413	51,370	23,413	0.00	0.01	0.02	0.01	0.01	0.02	0.01
Total	233,989	2,349,100	2,349,100	2,349,100	2,111,467	2,111,467	2,111,467	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Renewables	24,285	728,479	1,287,616	434,933	728,479	1,287,616	434,933	0.10	0.31	0.55	0.19	0.35	0.61	0.21
Fossil fuel	209,704	1,620,621	1,061,484	1,914,167	1,382,988	823,851	1,676,534	0.90	0.69	0.45	0.81	0.65	0.39	0.79
7% discount rate														
Standard deviation of levelised cost		0.013	0.011	0.016	0.013	0.010	0.016							
Expected levelised average cost (US$/kWh)		0.080	0.080	0.085	0.082	0.079	0.088							
with carbon price at 85 US/tCO2:														
Standard deviation of levelised cost		0.029	0.019	0.034	0.027	0.017	0.033							
Expected levelised average cost (US$/kWh)		0.131	0.111	0.145	0.128	0.106	0.145							
10% discount rate														
Standard deviation of levelised cost		0.014	0.012	0.016	0.014	0.011	0.016							
Expected levelised average cost (US$/kWh)		0.088	0.091	0.092	0.090	0.091	0.095							
with carbon price at 85 US/tCO2														
Standard deviation of levelised cost		0.029	0.020	0.034	0.027	0.017	0.033							
Expected levelised average cost (US$/kWh)		0.138	0.122	0.152	0.137	0.118	0.152							

Note: EE = energy efficiency. In the different scenarios, higher EE is equivalent to reduced energy demand, resulting in reduced generation. BAU plus 17% increase in EE = coal is reduced by 17% compared to BAU. Strong RE plus 17% higher EE = coal is reduced by 10%, combined cycle by 7% compared to Strong RE scenario. Weak RE plus 17% EE = coal-based generation is reduced by 17%.

Table A4: Impacts of solar power expansion on scenarios

		7 %, no carbon price						7%, carbon price of 41 US$/tCO2					
2035	Scenario	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E
Original	stev	0.014	0.010	0.016	0.014	0.009	0.016	0.019	0.012	0.022	0.018	0.012	0.021
	average LCOE	0.082	0.080	0.087	0.084	0.080	0.089	0.107	0.095	0.116	0.107	0.094	0.117
More solar	stev	0.014	0.009	0.016	0.014	0.008	0.016	0.019	0.011	0.022	0.018	0.010	0.021
	average LCOE	0.081	0.072	0.086	0.083	0.071	0.088	0.106	0.086	0.115	0.106	0.084	0.116
Difference	stev	0.000	**-0.001**	0.000	0.000	**-0.001**	0.000	0.000	**-0.001**	0.000	0.000	**-0.001**	0.000
	average LCOE	-0.001	**-0.008**	-0.001	-0.001	**-0.009**	-0.001	-0.001	**-0.009**	-0.001	-0.001	**-0.011**	-0.001

		2025, 7%, no carbon price						2025, 7%, with carbon price of 25US$/tCO2					
2025	Scenario	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E
Original	stev	0.016	0.013	0.017	0.016	0.012	0.018	0.018	0.014	0.020	0.018	0.013	0.020
	average LCOE	0.084	0.084	0.088	0.086	0.083	0.090	0.101	0.096	0.107	0.102	0.095	0.109
More solar	stev	0.014	0.009	0.016	0.014	0.008	0.016	0.019	0.011	0.022	0.018	0.010	0.021
	average LCOE	0.081	0.072	0.086	0.083	0.071	0.088	0.106	0.086	0.115	0.106	0.084	0.116
Difference	stev	-0.002	**-0.004**	-0.001	-0.002	**-0.004**	-0.001	0.001	**-0.003**	0.002	0.000	**-0.003**	0.002
	average LCOE	-0.003	**-0.012**	-0.002	-0.003	**-0.012**	-0.002	0.005	**-0.010**	0.007	0.004	**-0.011**	0.007

		2050, 7%, no carbon price						2050, 7%, with carbon price of 85 US$/tCO2					
2050	Scenario	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E	BAU	Strong RE	Weak RE	BAU + EE	Strong RE + EE	Weak RE + E E
Original	stev	0.013	0.011	0.016	0.013	0.010	0.016	0.029	0.019	0.034	0.027	0.017	0.033
	average LCOE	0.080	0.080	0.085	0.082	0.079	0.088	0.131	0.111	0.145	0.128	0.106	0.145
More solar	stev	0.014	0.009	0.016	0.014	0.008	0.016	0.019	0.011	0.022	0.018	0.010	0.021
	average LCOE	0.081	0.072	0.086	0.083	0.071	0.088	0.106	0.086	0.115	0.106	0.084	0.116
Difference	stev	0.001	**-0.002**	0.000	0.001	**-0.002**	0.000	-0.010	**-0.008**	-0.012	-0.008	**-0.006**	-0.011
	average LCOE	0.001	**-0.008**	0.000	0.001	**-0.008**	0.000	-0.024	**-0.025**	-0.031	-0.022	**-0.022**	-0.029

Chapter 8: Conclusion

This thesis was motivated by several seemingly contradictory policy trends. On the one hand, Indonesia has set ambitious policy targets of increasing the share of renewable energy (RE) in electricity supply and reducing greenhouse gas emissions relative to a baseline. On the other hand, plans to expand future electricity generation capacity are pushing coal-based power supply. Significant resources for generating RE remain under-utilised. As a result, Indonesia's economy and energy sector is likely to become locked into a carbon-intensive production mode, which in turn will undermine Indonesia's long-term economic and environmental sustainability.

Therefore, the key component of the thesis was to examine the specific barriers that stand in the way of a more expansive proliferation of RE investment in Indonesia. It did so by looking at three specific issues that were identified as research gaps in the existing literature. First, the thesis provided a historical analysis of the effectiveness of policies to incentivise RE supply in the Indonesian electricity sector. Second, it provided a detailed case study on the effectiveness of FITs in Indonesia. Third, it applied a risk-based method, MVP analysis, to analyse the risk and cost mitigation implications of increasing the share of renewables in PLN's long-term electricity supply mix. The key findings are summarised as follows.

Indonesia's energy path is in danger of being locked into coal in the coming decades, despite the existence of ample renewable resources and long-term programs to promote them. Analysis of the utility's electricity supply trends in the period 1990–2015 shows a significant increase in the role of coal and a relative decline of renewables in the generation mix. While the share of coal has increased significantly from 43 to 49 per cent, the share of renewables declined from 25 to 12 per cent from 1990–2015. This decline in the share of renewables has been driven by a large decrease in large-scale hydropower and stagnation of geothermal power generation. A closer look at the government's electricity expansion programs—specifically under FTP 1 and 2—shows that while coal- and gas-fired projects have been largely implemented, realisation of RE investment has been plagued by delays and uncertainties.

FITs and variants have been largely ineffective, particularly in the geothermal sector and in small and medium-sized RE production. Qualitative evidence from stakeholder interviews, analysis of the regulatory framework and a review of the relevant policy literature suggest that despite FITs being in place since the 1990s, PLN did not automatically take up renewables on a large scale. Most developers reported protracted PPA tariff negotiations with the utility, significantly slowing down implementation of projects, at least during the 2002–2012 period, when most of the data originates from.

What were the main causes for this state of affairs? The most important underlying factor is that coal and gas were cheaper than most renewables in the observed period and, thus, were the preferred options for PLN to generate electricity. Given that PLN constantly faced budget deficits and relied on a PSO subsidy to prop up its revenues, it naturally opted for least-cost options. The power of fossil fuel interests, China's support for promoting coal-based generation technology in Indonesia and PLN's familiarity with fossil fuel technologies are also factors hampering a quicker deployment of renewables. Past and existing FIT regulations were not capable to account for this and thus failed to sufficiently incentivise the utility to purchase more renewables and increase their share in the supply mix.

Given that the PLN is the main buyer of electricity on the grid, acting de facto as a monopsony, several design-related features of the FIT regulations worked against the proliferation of renewables. Above all, the Indonesian FITs were never designed as premium prices to attract enough investors like in 'best practice' countries such as Germany. The Indonesian regulations either set the purchasing prices lower than the utility's BPP, or, when later set at fixed prices, they still proved to be too low for many developers or alternatively too high for PLN to automatically take up renewables. Even when PPA negotiations took place, the absence of regularly updated and transparent information on BPP exacerbated uncertainty for IPPs. Finally, the lack of effectiveness of Indonesia's FIT regimes has been further accentuated by uncertainties associated with wider investment climate issues such as overlapping regulations and complex licensing processes.

Set against the wider literature on the effectiveness of RE policy instruments, the Indonesian case study somehow presents a 'mixed bag' in the sense that it confirms some of the factors and constraints affecting the use of FITs in developing countries, but also adds new aspects that are specific to the Indonesian energy governance context.

One insight from the literature review is that in high and middle-income countries, FITs were relatively successful in promoting the production of RE between 1990 and 2010. Specifically, FITs were quite effective in increasing RE production of non-hydropower RE sources. In contrast, low-income countries—including Indonesia in the period of the study—have mainly relied on subsidies, rather than FITs, to stimulate growth in non-hydropower RE production.

This suggests that, to some extent, income levels do affect RE outcomes, as low-income countries prefer more simple instruments such as subsidies to prioritise access to electricity and increase the reliability of grids. Instruments such as FITs or RPS are technology-based instruments, which require a higher administrative capacity. Moreover, other non-policy drivers of RE such as political capture and political freedom do play also a role. The former plays a more significant role in high-income countries, as fossil fuel industry interests use their political and economic clout to exclude RE from electricity markets. In low-income countries, the results of the study suggest that political freedom is a significant factor in determining investment in renewables.

The Indonesian case study contributes to the literature by showing that the transition from a low to a middle-income economy does not necessarily ensure a gradual improvement in the effectiveness of FITs to stimulate RE production. As shown in the thesis, Indonesia has implemented FIT regulations since the 1990s and the gradual improvement in the country's income level and public finances have not really resulted in large-scale RE production.

The key issue here is that the FIT regime has been largely undermined by the reluctance of state utility PLN to credibly commit, adopt and invest in RE targets. FITs, understood as premium prices to incentivise renewable IPPs, cannot work in an environment in which fossil fuels are cheaper than renewables and the utility is primarily concerned with cost and loss minimisation when purchasing electricity. This suggests that the institutional constraints—primarily the financial governance that shape tariff and subsidy regimes—under which a utility operates are key factors in determining the effectiveness of RE policy instruments.

The thesis shows how this lack of commitment by PLN to take up renewables at mandated FIT rates does undermine investment confidence on the side of IPPs. The interviews employed in this thesis reveal how PPA agreements between PLN and IPPs are resolved only at a slow pace, despite mandated tariff rates. In this regard, the thesis contributes some empirical evidence to the literature on the interaction between energy policy stakeholders and the role of trust (or lack thereof) in RE project implementation.

The findings of the thesis do confirm evidence from other developing country case studies that substantial financial support from outside the government budget is needed to back up FIT schemes. Much of the literature points to the need to have some international funding mechanism in place—at least in the early stages—to secure the financial footing of FIT schemes. Given the government's fiscal and PLN's financial constraints, this rings especially true for the Indonesian context.

Given that the utility's financial constraint is an important factor, its perception of risk when investing in generation technologies does matter. In the past, PLN's choice of coal over renewables was perfectly rational, as coal was the cheapest option. This is still reflected in PLN's long-term supply planning scenarios, which foresees a continued strong role of coal-fired generation. However, with the rapid decline of costs of renewables such as solar and wind power technologies, the utility may want to apply a more comprehensive risk analysis to account for the significant advantage of renewables over non-renewables in terms of zero fuel price risk.

MVP theory provides a framework that treats the electricity supply mix as a portfolio consisting of shares of individual fossil fuel and renewable technologies, each with different cost and cost risk profiles. Cost risk is defined as the variation in past cost streams of individual technologies, measured by the standard deviation of those costs.

From a cost risk perspective, the lowest levels of risk in the Indonesian electricity sector are associated with small-scale renewables such as wind, solar and small hydropower. This can be mainly explained by the absence of fuel price risks and the low standard deviations associated with capital/construction. The highest risks are associated with those technologies that are tied to fuel price risks such as coal and have large construction/capital risks, including renewables like large hydropower and geothermal.

When applying MVP analysis to PLN's long-term energy supply mix scenarios to assess the benefits of diversifying the electricity supply mix, the following picture emerges. Cost effects are relatively small, but the difference in risks across the generation technologies is significant. Portfolios with SR and combined with higher energy efficiency outcomes represent the most efficient baskets, as they optimise cost and risk minimisation. Conversely, portfolios with a small share of renewables do present the costlier and riskier options. A higher discount rate at 10 per cent does not change the risk profiles significantly, but pushes costs slightly higher for all portfolios, including those containing more renewables. Adding carbon prices increases the risks and costs for all portfolios but is more pronounced for those portfolios with a high share of fossil fuel–based technologies. Finally, an increase in the share of solar power technologies combined with a lower levelised cost of electricity further reduces the costs and risks of the SR scenario portfolio.

These results are in line with the estimated cost and cost risk profiles for generation technologies in the Indonesian electricity sector. The lower risk profile for renewables, mainly due to the absence of fuel price risks, should decrease risks for a portfolio containing more renewables. Conversely, a higher price risk, associated with fossil fuel–based technologies should push fossil fuel–heavy portfolios further up the risk axis.

Several policy implications can be derived from this thesis. One major policy implication is about the relative effectiveness of price- versus quantity-based policy instruments in an environment where fossil fuels such as coal and gas have historically been cheaper options than renewables. Designed as purely price-based instruments, past and present FIT regulations do not provide a strong enough mandatory mechanism for PLN to take up renewables. The utility behaves as a cost-minimising monopsony on the national grids and has the leverage to influence the final purchasing price of each PPA contract. Without a mandatory quantity target, a price-based instrument cannot force PLN to commit to, adopt and invest in RE targets.

A stronger role for quantity-based instruments seems to be the way forward if policymakers are serious about reaching renewables targets. Quota obligations for utilities have been used in various countries, such as RPS, RESs, Renewables Obligations and RETs. Under these quota systems the utility is obliged to take up renewables into the grid and any additional costs can be passed on to the consumer.

However, going forward, renewables will become more competitive in Indonesia, as the global costs of technologies such as solar and wind power are already declining. The costs and risks calculated in this thesis and their application in the numerical simulations under the portfolio modelling do already take account of a narrow cost difference between fossil fuel and renewables. As shown, portfolios with larger shares of renewables and higher energy efficiency have lower cost and cost risk levels. Thus, the cost advantage of coal is disappearing, making it even more imperative for PLN to fully move to renewables in the next few years.

As renewables become cheaper, is there still a need for the government to use regulatory instruments to incentivise investment? One major reason to do so is that while many renewables are now competitive on a levelised cost basis, the upfront cost of renewables are generally higher. Moreover, given PLN's fossil fuel–oriented business model, there is lack of experience in adopting new business models based on intermittent technologies and storage. New battery technologies for solar or pumped hydro are becoming increasingly cost-effective solutions to overcome barriers to entry for renewables in Indonesia. All the above factors still give coal and gas an advantage over renewables, given PLN's financial constraints. Therefore, price and quantity instruments can still play an important role in overcoming the institutional bias within PLN against renewables, especially in a period of transition in which the government is gradually phasing out electricity tariffs and subsidies.

A continued decline in the cost of renewables and an improvement of PLN's finances could see a more effective implementation of instruments such as FITs and RPSs. A decline in the cost of renewables would gradually lessen the need for FITs to be set at levels high enough to act as an attractive premium price. Once cost parity with coal and gas is achieved—and this process depends on the regional cost differences across grids in Indonesia—FITs for renewables would not be needed anymore.

Similarly, RPSs could function as a complementary tool to guarantee that if mandatory quantitative targets are not achieved, then the premium prices are automatically raised to provide sufficient incentives. Reverse auction for solar power, as successfully implemented in India, is also a promising instrument for Indonesia to consider.

The high cost risks associated with large geothermal and hydropower projects suggest that wider macroeconomic instruments should also play a part in making investment into renewables more attractive. The government's ongoing reform to reduce fuel subsidies and introduce cost-reflective electricity tariffs has a direct impact on PLN's finances and might in future enable the utility to purchase renewables with FITs set at premium levels.

Policies that reduce capital and construction risks could make large-scale hydropower and geothermal projects more feasible. The government could push fiscal policies to provide tax exemptions for importing renewable technologies or generally make sure that there are no import barriers. De-risking large geothermal and hydropower projects could also take the form of providing risk guarantees and improving land acquisition policies.

Several limitations of the research findings and methodology need to be outlined, with suggestions for further research. One limitation is that the perceptions of stakeholders on the effectiveness of the FIT regulations only cover the period before 2012. As these regulations have been revised since, there is scope for future research to analyse the effectiveness of these revised tariffs. The solar power FITs, for example, have undergone several revisions in both design and price levels between 2012 and 2017, although only a few projects have been implemented. A stakeholder analysis could provide useful insights on the political economy process shaping the design of RE regulations in general and FIT regulations in particular.

Given that there are no academic studies that have fully applied MVP as an analytical tool to assess the Indonesian electricity and RE sectors, this thesis is a new contribution to the literature on financial and cost risk assessment of generation technologies. Hence, there is also ample room to extend the MVP analysis and make it more sophisticated. One weakness of the methodology as applied in this thesis is that the load structure of the technology mix is not being included in the model, an inherent problem with many studies applying the MVP method. Another limitation is that, traditionally, MVP is mostly used to assess financial risks, defined as variations in investment returns in the power sector. Within the Indonesian context, this thesis focusses on the interaction between cost risk—the variation of cost streams of individual generation technologies—and portfolio risk. Moreover, given data limitations, the thesis has not distinguished between risks associated with on-grid and off-grid projects, with the latter including captive power generation which can be quite significant in certain regions. Finally, there is scope to undertake MVP analysis for individual and regional grids in Indonesia. Each grid has a different supply mix and faces different regional cost structures, so an MVP analysis that captures sub-national markets could provide important insights to policymakers.

Despite the aforementioned limitations, this thesis presents novel insights and contributes in various ways to the literature on energy policies in developing countries. First, it provides a detailed historical and empirical analysis of the effectiveness of policies to incentivise RE supply in the Indonesian electricity sector. The thesis finds that a combination of regulatory uncertainty in the power sector, financial weakness of the national electricity utility PLN, and ineffective FITs have had a dampening effect on RE investment. FITs have been rendered ineffective as they were set at levels too low to act as premium prices to attract investment on a large scale.

Second, the thesis contributes to the literature on risk assessment in the energy sector by applying MVP theory to analyse the risk-mitigation potential of renewables in PLN's future electricity supply mix. Findings suggest that the risk of investing in the power sector, defined as cost risk and measured by the standard deviation of past cost streams, differs significantly across generation technologies and is lower for renewables. Energy portfolios containing a large share of renewables combined with energy efficiency measures are now preferable in cost and risk terms, although at higher discount rates the cost advantage is less pronounced.

Going forward, policy reforms need to focus on continuing to move towards cost-reflective tariffs to improve PLN's financial footing. Combined with continued declining costs of renewables, FITs could become more effective when set at levels that truly act as premium prices. They could be combined with quantitative instruments such as RPSs to help overcome institutional bias against renewables within PLN, especially in a period of transiting towards a cost-effective tariff system and phasing out of subsidies.

References

Aldy, J & Stavins, R 2007, *Architectures for agreement: Addressing global climate change in the post-Kyoto world*, Cambridge University Press, Cambridge.

Asian Development Bank 2003, *Impact evaluation study of Asian Development Bank assistance to the power sector in Indonesia*, ADB, Manila.

Asian Development Bank 2009, *The economics of climate change in Southeast Asia: a regional review*, ADB, Manila.

Asian Development Bank & The World Bank 2015, *Unlocking Indonesia's geothermal potential*, Asian Development Bank and The World Bank, Jakarta, https://openknowledge.worldbank.org

Asian Development Bank 2016, *Indonesia energy sector assessment, strategy and roadmap,* Asian Development Bank, Manila.

Auriga 2017, *Private gain, public risk. Guarantees and credit enhancement for coal-fired power plants in Indonesia*, http://auriga.or.id/private-gain-public-risk-guarantees-credit-enchancement-for-indonesias-coal-fired-power-plants/

Australia Unlimited 2012, *Market research report. Trade opportunities. Low emissions technology services*, Canberra.

Awerbuch, S & Yang, S 2008, 'Maximizing energy security and climate change mitigation', in B Morgan & F Roques (eds.), *Energy diversity and security. Portfolio optimization in the energy sector: a tribute to the work of Dr. Shimon Awerbuch*, Elsevier, Amsterdam, pp. 85–116.

Bacon, F, Besant-Jones, F, Heiduriona, J 1996, Estimating construction costs and schedules: Experience with power generation, World Bank Technical Paper no.325 (August), World Bank, Washington D.C.

Baker McKenzie 2017. Indonesian Government puts the squeeze on renewable energy tariffs, https://www.bakermckenzie.com/-/media/files/insight/publications/2017/02/

indonesia-govt-renewable-energytariffs/al_indonesia_govtrenewableenergytariffs_feb2017.pdf?la=en

Bakhtiar, B, Sopian, K, Zaharim, A, Salleh, E & Lim, CH 2013, 'Potential and challenges in implementing feed-in-tariff policy in Indonesia and the Philippines', *Energy Policy*, vol. 60, pp. 418–423.

Baldwin, E, Sanya, C, Brass, JN & MacLean, LM 2017, Global renewable electricity policy: a comparative analysis of countries by income status, *Journal of Comparative Policy Analysis: Research and Practice*, vol. 19, no. 3, pp. 277–298, http://dx.doi.org/10.1080/13876988.2016.1166866

BAPPENAS 2015, *BAU Baseline Emisi Indonesia (Hasil Kaji Ulang)*, Bappenas, Jakarta.

Bazilian, M & Roques, F (eds.) 2008, *Energy diversity and security. Portfolio optimization in the energy sector: a tribute to the work of Dr. Shimon Awerbuch*, Elsevier, Amsterdam.

Beaton, C & Lontoh, L 2010, *Lessons learned from Indonesia's attempts to reform fossil-fuel subsidies*, International Institute for Sustainable Development, Winnipeg, Manitoba.

Besant-Jones, JE 2006, *Reforming power markets in developing countries: What have we learnt?*, Energy and Mining Sector Board discussion paper no. 19, World Bank, Washington D.C.

Bhattacharya, A 2012, 'Power sector investment risk and renewable energy: a Japanese case study using portfolio risk optimization method', *Energy Policy*, vol. 40, no. 1, pp. 69–80.

Bowen, WW, Park, S & Elvery, JA 2013, Empirical estimates of the influence of renewable energy portfolio standards on the green economy of states, *Economic Development Quarterly* vol. 27, no. 4, pp. 338–351.

Brealey, RA & Myers, SC 2000, *Principles of corporate finance*, 6th edn, Irwin McGraw–Hill, Boston.

Burke, PJ 2010, ‘Income, resources and electricity mix’, *Energy Economics*, vol. 32, no. 3, pp. 616–626.

Burke, PJ & Liao, H 2015, ‘Is the price elasticity of coal in China increasing?’, *China Economic Review*, vol. 36, pp. 309–322.

Burke, PJ & Kurniawati, S 2018, Electricity subsidy reform in Indonesia: demand-side effects on electricity use, *Energy Policy*, vol. 116, pp. 410–421.

Carley, S 2011, *Decarbonization of the US electricity sector: are state energy policy portfolios the solution?*, Munich Personal RePEc archive paper No. 2856, https://mpra.ub.uni-muenchen.de/28256/

Castlerock 2010, *Phase 1 report: review & analysis of prevailing geothermal policies, regulations and costs*, Ministry of Energy and Mineral Resources, Jakarta.

Castlerock 2011, *Phase II geothermal report*, Ministry of Energy and Natural Resources, Jakarta.

Castlerock 2012, *Micro Hydro Power (MHP) return of investment and cost effectiveness analysis. Final report*, The World Bank Group, Jakarta.

Climate Bonds Initiative 2018, *Green infrastructure investment opportunities in Indonesia*, https://www.climatebonds.net/files/reports/climate_bonds_giio_indonesia_report_may2018.pdf

Davies, LR 2012, ‘Reconciling renewable energy standards and feed-in-tariffs’, *Utah Environmental Law Review*, vol. 32, no. 92, pp. 311–361.

De Paz, FL & Silvosa, AC 2012, ‘The problem of determining the energy mix: from the Portfolio Theory to the reality of energy planning in the Spanish case’, *Eur. Res. Stud. J.*, vol. 15, pp. 3–30.

Dethier, HM & Straub, S 2011, ‘Explaining enterprise performance in developing countries with business climate survey data’, *The World Bank Research Observer*, vol. 26, no. 2, https://openknowledge.worldbank.org/handle/10986/13517

DNV (De Norske Vertias) 2010, *Validation report: Parluasan hydroelectric power plant, Report No. 2010-9060*, Veritasvn, Hovik, Norway.

Dornan, M & Jotzo, F 2012, *Renewable technologies and risk mitigation in small island developing states (SIDS): Fiji's electricity sector*, discussion paper no. 13, Development Policy Center, ANU, Canberra.

Dornan, M & Jotzo, F 2015, '*Renewable technologies and risk mitigation in small Island developing states: Fiji's electricity sector*', *Renewable and Sustainable Energy Reviews*, vol. 48, pp. 35–48.

Dubash, N (ed.) 2002, *Power politics: equity and environment in electricity reform*, World Resources Institute, Washington D.C.

EIA (Energy Information Administration) 2013, *Indonesia country brief*, US Department of Energy, Washington D.C.

EIA (Energy Information Administration) 2012, *Annual energy outlook 2012*, US Department of Energy, Washington D.C.

EIA (Energy Information Administration) 2012a, *Assumptions to the annual energy outlook*, US Department of Energy, Washington D.C.

Electricity Power Research Institute (EPRI) 2015, *Australia power generation technology report*, CO2CRC Limited, Melbourne, http://old.co2crc.com.au/dls/brochures/LCOE_Executive_Summary.pdf

Estache, A & Wren-Lewis, L 2009, 'Toward a theory of regulation for developing countries: following Jean-Jaques Laffont's lead', *Journal of Economic Literature*, vol. 47, no. 3, pp. 729–770.

Ferrey, S 2004, *Small power purchase agreement application for renewable energy development: lessons from five Asian countries*, The World Bank, Washington D.C.

Fischer, C 2009, 'Renewable portfolio standards: when do they lower energy prices?', *The Energy Journal*, vol. 30, no. 4, pp. 81–100.

Food and Agricultural Organization 1990, *The community's toolbox: the idea, methods, and tools for participatory assessment, monitoring and evaluation in community forestry*, FAO, Bangkok, Thailand.

GDF Suez 2014, *Ponggang mini hyro project*, Presentation material August 2014, Jakarta.

GeothermEX Inc. 2010, *An assessment of geothermal resource risks in Indonesia*, Ministry of Energy and Mineral Resources and Public private Infrastructure Advisory Facility, Jakarta.

Ginting, A, Newell, D, Mustakim, P & Slamet, U 2010, Developing geothermal energy in a changing regulatory environment', in *Proceedings of World Geothermal Congress*, Bali, Indonesia, pp. X–X.

GIZ 2011, *GIZ – NREEC implementation plan mini hydro power project for capacity development*, GIZ, NREEC and Ministry of Energy and Mineral Resources, Jakarta.

Global Green Growth Institute (GGGI) 2016, *Biomass power generation in East Kalimantan*, Unpublished pre-feasibility study, GGGI, Jakarta.

Gravelle, H & Rees, R 1992, *Microeconomics*, Longman, London and New York.

GTZ 2009a, *Brief policy review of the DME program*, GTZ Indonesia, Jakarta.

GTZ 2009b, *Technical and strategic input for the further development of the DME program*, GTZ Indonesia, Jakarta.

Huenteler, J 2014, 'International support for feed-in tariffs in developing countries–A review and analysis of proposed mechanisms', *Renewable and Sustainable Energy Reviews*, vol.39, pp. 857-873.

Hutapea, M 2012, *Reviewing opportunities for bioenergy and waste to energy development in Indonesia.*

Indonesia Wind Energy Society 2012, *Wind energy potential and development in Indonesia*, presentation at the Clean Power Asia Conference, Bali, 14–15 May.

International Energy Agency 2015, *Projected costs of generating electricity*, OECD, Paris.

International Energy Agency 2008, *Energy policy review of Indonesia*, OECD and IEA, Paris.

International Energy Agency 2009, *Sectoral approaches in electricity - building bridges to a safe climate*, IEA and OECD, Paris.

International Energy Agency 2015, *Indonesia 2015 - energy policies beyond IEA countries*, IEA, Paris.

International Energy Agency 2016, *World energy outlook 2016*, IEA, Paris.

International Energy Agency & Organisation for Economic Co-operation and Development 2009, *World energy outlook 2009*, OECD and IEA, Paris.

Ioannou, A, Angus, A & Brennan, F 2017, 'Risk-based methods for sustainable energy system planning: a review', *Renewable and Sustainable Energy Reviews*, vol. 74, pp. 602–615.

IPCC 2011, *Special report on renewable energy sources and climate change mitigation*, Cambridge University Press, Cambridge.

IRENA (International Renewable Energy Agency) 2012a, *Renewable power generation costs in 2012: an overview*, IRENA, Bonn.

IRENA (International Renewable Energy Agency) 2012b, *Hydropower. Renewable energy technologies: cost series, volume 1: power secto*r, IRENA, Bonn.

IRENA (International Renewable Energy Agency) 2012c, *Wind power. Renewable energy technologies: cost series, volume 1: power sector*, IRENA, Bonn.

IRENA (International Renewable Energy Agency) 2012d, S*olar PV. Renewable energy technologies: cost series, volume 1: power sector*, IRENA, Bonn.

IRENA (International Renewable Energy Agency) 2012e, *Biomass. Renewable energy technologies: cost series, volume 1: power sector*, IRENA, Bonn.

IRENA (International Renewable Energy Agency) 2012f*, Power to change: Solar and wind cost reduction potential to 2025*, IRENA, Bonn.

IRENA (International Renewable Energy Agency) 2016, *Renewable energy statistics*, IRENA, Bonn.

Jamasb, T 2006, 'Between the state and market: electricity sector reform in developing countries', *Utilities Policy*, vol. 14, no. 10, pp. 14–30.

JICA 2009, *Study on fiscal and non-fiscal incentives to accelerate private sector geothermal energy development in the Republic of Indonesia*, http:// http://open_jicareport.jica.go.jp/pdf/12008710.pdf

Kopenindo 2008, *Wangan Aji micro hydropower project – final report submitted to ADB Poverty and Environment Program*, ADB, Jakarta.

Kornai, J, Maskin, E & Roland, G 2003, 'Understanding the soft budget constraint', *Journal of Economic Literature*, vol. 41, pp. 1095–1136.

Kristov, L 1995, 'The price of electricity in Indonesia', *Bulletin of Indonesian Economic Studies*, vol. 31, no. 3, pp. 73–101.

Labandeira, X & Linares, P 2010, *Second-best instruments for energy and climate policy*, Economics for Energy working paper no. 06/2010, https://eforenergy.org/docpublicaciones/documentos-de-trabajo/WP06-2010.pdf

Laffont, J 2005, *Regulation and development*, Cambridge University Press, Cambridge.

Laffont, J 2001, *Incentives and political economy*, Oxford Scholarship, DOI: 10.1093/0199248680.001.0001.

Lakatos, A 2004, 'Overview of regulatory environment for trade in electricity', in J Bilecki & MG Desta (eds.), *Electricity trade in Europe: review of economic and regulatory challenges*, Kluwer Law International, The Hague, pp. 119–154.

Markowitz, HM 1952, 'Portfolio selection', *Journal of Finance*, vol. 7, pp. 77–91.

McCawley, P 1978, 'Rural electrification in Indonesia: is it time?', *Bulletin of Indonesian Economic Studies,* vol. 14, no. 92, pp. 34–69.

McCawley, P 1970, ‘The price of electricity’, *Bulletin of Indonesian Economic Studies*, vol. 31, no. 3, pp. 61–86.

Mendoncana, M, Jacobs, D & Sovacol, BK 2009, *Powering the green economy: the feed-in-tariff handbook*, Earthscan, London.

Ministry of Energy and Mineral Resources 2011, *PLN* e*lectricity tariffs and subsidies*, Presentation Material (Indonesian version), 30 September 2011, Jakarta.

Ministry of Finance 2009, *Green paper on economic and fiscal policy options for climate change mitigation*, Ministry of Finance Indonesia, Jakarta.

Mubariq, A 2010, *Low carbon economy scenarios: results of dynamic IR-CGE model simulations in comparison with baseline*.

Najamuddin, H 2012, *Future outlook of PLN's coal-fired power plants*, presentation of Head of PLN Coal Division at Japan Coal Energy Center (JCOAL), Japan.

National Renewable Energy Laboratory (NREL) 2016, Simple levelised cost of energy (LCOE) calculator Documentation, http://www .nrel.gov/analysis/ tech_lcoe _ documentation.html?print.

Norton Rose 2012, *Indonesian power projects: ten things to know*, http://www.nortonrosefulbright.com/knowledge/publications/133993/indonesian-power-projects

Organisation for Economic Co-operation and Development & International Energy Agency 2009, *World Energy Outlook 2009*, Paris.

PLN 2005, *Update of the electricity tariff rationalization study: final report. Unpublished report for PT PLN*, PT PA Consulting Indonesia, Jakarta.

PLN 2009, *Rencana Perusahaan Penyediaan Tenaga Listrik 2009-2018*, Jakarta.

PLN 2010a, *Prospektus PT Perusahaan Listrik Negara (Persero)*, PLN Persero, Jakarta.

PLN 2010b, *Rencana Perusahaan Penyediaan Tenaga Listrik 2010-2019*, Jakarta.

PLN 2011a, *Annual report 2011*, Jakarta.

PLN 2011b, *Rencana Perusahaan Penyediaan Tenaga Listrik 2011-2020*, Jakarta.

PLN 2011c. *Status Pengadaan IPP (Agustus 2011)*, PLN, Divisi Pengadaaan IPP, Jakarta.

PLN 2012a, *Annual report 2011*, Jakarta.

PLN 2012b, *Rencana Perusahan Penyediaan Tenaga Listrik 2012-2021*, PLN.

PLN 2013, *Rencana Perusahan Penyediaan Tenaga Listrik 2013-2022*, Jakarta.

PLN 2016a, *PLN financial statement 2016*, Jakarta.

PLN 2016b, *Rencana Perusahan Penyediaan Tenaga Listrik 2016-25*, Jakarta.

Purra, M 2009, *The Indonesian electricity sector: institutional transition, regulatory capacity and outcomes*, Centre on Asia and Globalization, Lee Kuan Yew School of Public Policy, National Unversity of Singapore, Singapore.

PWC 2011, *Electricity in Indonesia. Investment and taxation guide*, Jakarta.

PWC 2016, Power *in Indonesia. Investment and taxation guide*, Jakarta.

Rea, LM & Parker, RA 2005, *Designing and conducting survey research. A comprehensive guide*, John Wiley & Sons, San Francisco.

REN21 2011, *Renewables 2011: global status report*, REN21 Secretariat, Paris.

REN21 2016, *Renewables 2016: global status report*, REN21 Secretariat, Paris.

Resosudarmo, B & Abdurohman 2011, *Green fiscal policy and climate change mitigation in Indonesia*, working paper no. 1109, Centre for Climate Economics and Policy, Crawford School of Economics and Government, ANU.

Resosudarmo, B & Burke, PJ 2012, ‘Survey of recent developments’, *Bulletin of Indonesian Economic Studies*, vol. 48, no. 3, pp. 299–324.

Rickerson, W, Hanley, C, Laurent, C & Gaecen, C 2013, ‘Implementing a global fund for feed-in-tariffs in developing countries: a case study of Tanzania’, *Renewable Energy*, vol. 49, pp. 29–32.

Sambodo, MT 2015, ‘Rural electrification program in Indonesia: comparing SEHEN and SHS Program’, *Economics and Finance in Indonesia*, vol. 61, no. 2, pp. 107–119.

Sanyal, S 2004, *Cost of geothermal power and factors that affect it*, GeothermEx.

Sarwono, H & Siswoyo, SD 2008, ‘Development of mini/micro hydro power plant for rural electricity in Indonesia’, *Jurnal Ilmiah Teknologi Energi*, vol. 1, no. 6, pp. 1–12.

Seymour, F & Sari, AP 2002, ‘Indonesia: electricity reform under economic crisis’, in N Dubash (ed.), *Power politics: equity and environment in electricity reform*, World Resources Institute, Washington D.C., pp. 75–96.

Siwage, N 2014, ‘Prospek dan Strategi Pengembangan Energi Panas Bumi Sebagai Energi Alternatif Masa Depan’, in T Ermawati and SD Negera (eds.), *Pengembangan Industri Energi Alternatif: Studi Kasus Energi Panas Bumi Indonesia*, LIPI Press, Jakarta, pp. X–X.

Sofyan M 2011a, *Program Energi Terbarukan*, presentation at Seminar Nasional Pascasarjana, ITS, Surabaya, 27 July.

Sofyan, M 2011b, *PLN solar development plan: target and experiences*, presentation at German - Indonesian Renewable Energy Days, Jakarta, 26 October.

Sovacool, BK 2010, ‘A comparative analysis of renewable electricity support mechanisms for Southeast Asia’, *Energy*, vol. 35, no. 4, pp. 1779–1793, http://www.sciencedirect.com/science/article/pii/S0360544209005507

Strategic Asia 2012, *Public private partnerships in Indonesia: opportunities from the economic masterplan*, Jakarta.

Synnerstrom, S 2007, ‘The civil service: towards efficiency, effectiveness and honesty’, in R McLeod and A McIntyre (eds.), *Indonesia: democracy and the promise of good governance*, Institute of Southeast Asian Studies, Singapore, pp. 159–177.

Tumiwa, F 2010, *Scaling up renewable energy investments: lessons from best practice models*, Indonesia Institute for Essential Services Reform, Jakarta.

TUV Sued Industry Service 2008, *Validation report: PT Listrindo Kencana biomass power plant*, TUV Sued Industry Service, Essen.

TUV Nord 2011, *Validation report: PT Sulawesi mini hydro power. 10 MW Tangka Manipi hydro electric power plant. Report no. 010904247-09/299*, TUV Nord, Essen.

TUV Rhineland 2012, *Mobuya Mini hydro power plant 3x1000 kW North Sulawesi, Indonesia. Report no. 963246*, TUV Rhineland, Essen.

United Nations Development Programme 2007, *Promoting environmentally sound and renewable energy resources through Integrated Microhydro Development and Application Program (IMIDAP)*, UNDP and Government of Indonesia, Jakarta.

United Nations Framework Convention on Climate Change 2010a, *Project design document form: Darajat Unit III geothermal project*, http://cdm.unfccc.int/Projects/DB/KPMG1159285050.32

United Nations Framework Convention on Climate Change 2010b, *Project design document (PDD): Parluasan hydro electric power plant. Document version 5 04/11/2010*, UNDP, Jakarta.

United Nations Framework Convention on Climate Change 2011a, *Project design document: mini hydro Lobong Mongango Merasap PLN. Version 1 (18 August 2011)*, http://cdm.unfccc.int/Projects/Validation/DB/L3KPI87UHGPEH4MYLGST8ZQZADC7TD/view.html

United Nations Framework Convention on Climate Change 2011b, *Project design document (PDD): Genyem PLN Hydropower Project*, UNDP, Jakarta, https://cdm.unfccc.int/Projects/DB/RWTUV1286278945.63/view

United Nations Framework Convention on Climate Change 2011c, *Project design document (PDD): 10 MW Tangka/Manipi hydro electric power plant. Document version 18. 12/1/2011*, https://cdm.unfccc.int/Projects/DB/RWTUV1286278945.63/view

United Nations Framework Convention on Climate Change 2012, *Project design document (PDD): Tarabintang 2x5 MW mini hydropower plant*, https://cdm.unfccc.int/Projects/DB/RWTUV1286278945.63/view

USAID 2009, *Indonesia energy assessment*, USAID, Jakarta.

Victor, D 2011, Global warming gridlock: Creating more effective strategies for protecting the planet, Cambridge University Press, Cambridge.

Vitahayasrichareon, P, McGill, I & Nakawiro, T 2010, *Sustainability challenges for electricity industries in ASEAN newly industrializing countries*, presentation at IASTED Conference on Power and Energy System, Phuket, Thailand 24–26, November.

Wells, L & Ahmed, R 2007, *Making foreign investment safe. Property rights and national sovereignty*, Oxford University Press, Oxford.

Wijaya, L & Limmeechokchai, B 2011, 'Impacts of coal price on Indonesian electricity planning: The oil price perspective and CO2 emissions', *Thammasat International Journal of Science and Technology*, vol. 16, no. 1, pp. 78–89.

Winarno, D 2011, *Penyusunan Usulan Harga Jual Listrik Dari Pembangkit Berbasis Biomasssa dan Biogas [Proposal for Electricity Prices from Biomass Sources]*, presentation at Indonesian Renewable Energy Society (METI), 4 October.

World Bank 1996, *Republic of Indonesia Solar Home Systems Project. Project Document*, World Bank, Washington D.C.

World Bank 2001, *Implementation completion report on a loan in the amount of US$20 million to the Republic of Indonesia for a Solar Home Systems Project. Report no. 22588*, World Bank, Washington D.C.

World Bank 2005, *Electricity for all: options for increasing access in Indonesia*, World Bank, Infrastructure Department, East Asia and Pacific Region.

World Bank 2007, *Spending for development: making the most of Indonesia's new opportunities*, World Bank, Jakarta.

World Bank 2010, Green PNPM - annual status report, World Bank, Jakarta.

World Bank 2011a, *Indonesian Economic Quarterly* (June), World Bank, Jakarta.

World Bank 2011b, *Indonesian Economic Quarterly* (December), World Bank, Jakarta.

World Bank 2011c, *Climate change and fiscal policy - a report for APEC*, World Bank, Washington D.C.

World Bank 2011d, *Project appraisal document on a proposed loan - Geothermal Energy Investment Project*, World Bank, Washington D.C.

World Bank, Ecofys & Vivid Economics 2016, *State and trends of carbon pricing 2016*, World Bank, Washington D.C.

World Economic Forum 2012, *The global competitiveness report 2012-13*, World Economic Forum, Geneva.

World Economic Forum 2014, *The global competitiveness report 2014-15*, World Economic Forum, Geneva.