IESR

A Roadmap for Indonesia's Power Sector:

How Renewable Energy Can Power Java-Bali and Sumatra

in cooperation with:

MONASH University

MONASH ENERGY MATERIALS AND SYSTEMS INSTITUTE (MEMSI)

The Australia-Indonesia Centre

Agora Energiewende

A Roadmap for Indonesia's Power Sector:
How Renewable Energy Can Power Java-Bali and Sumatra

IMPRINT

A Roadmap for Indonesia's Power Sector: How Renewable Energy Can Power Java-Bali and Sumatra

Study by:

Monash Grid Innovation Hub/Australia Indonesia Centre
Monash Energy Materials and Systems Institute
Monash University
Wellington Rd, Clayton VIC 3800 | Australia
T: +61 9905 1049
www.monash.edu | memsi@monash.edu

Institute for Essential Services Reform
Jalan Tebet Barat Dalam VIII No. 20 B
Jakarta Selatan 12810 | Indonesia
T: +62 21 2232 3069 | F: +62 21 8317 073
www.iesr.or.id | iesr@iesr.or.id

Agora Energiewende
Anna-Louisa-Karsch-Straße 2
10178 Berlin | Germany
T: +49 30 700 14 35-000 | F: +49 30 700 14 35-129
www.agora-energiewende.org | info@agora-energiewende.de

Study Team:

Dr. Ariel Liebman - Monash Grid Innovaton Hub
Warwick Forster - Apogee Energy
Mentari Pujantoro and Philipp Godron - Agora Energiewende
Fabby Tumiwa, Jannata Giwangkara, and
Agus Tampubolon - Insttute for Essental Services Reform

The technical report was written by:

Ariel Liebman, Monash Grid Innovation Hub
Warwick Foster, Apogee Energy

Editor:

Fabby Tumiwa and Agus Praditya Tampubolon, Institute for Essential Services Reform

This report should be cited:
IESR (2019), A Roadmap for Indonesia's Power Sector: How Renewable Energy Can Power Java-Bali and Sumatra, Institute for Essential Services Reform (IESR), Jakarta

Publication:

February 2019

Foreword

Dear reader,

Indonesia is the world's 4th most populous country on a contnuous growth trajectory. To supply the increasing electricity demand, the government is emphasizing the role of fossil, and, in partcular coal-fired generaton, which is supposed to grow to 65% of total generaton. At the same tme, it stpulates that by 2025, Renewable energy shall make up 23% of primary energy mix, up from 8% today. Policy focus is on hydro and geothermal resources, while solar and wind power play only a negligible role.

Globally, the trend is very different: power systems around the world are increasingly being shaped by renewables. Solar and wind – driven by significant technology cost reducton - have been at the forefront of power sector investment for years and will contnue to play the decisive role in modernizing and decarbonizing power systems globally.

Against this background, we conducted a model-based powers system analysis, performed with the PLEXOS model which is widely used for power sector analysis. The study focuses on the Java-Bali and Sumatra systems, which is where the majority of the populaton lives and about 90% of the electricity is produced and consumed. The model assesses both the demand and supply dimensions of the power system.

Looking ten years ahead, we have assessed different pathways for the Indonesia's power system: what are the impacts of a moderate electricity demand growth on investment and power plant utlisaton? What is the impact of adding considerable shares of wind and solar capacity to system cost, and how will the system ensure security of supply?

Fabby Tumiwa

Executve Director

IESR | A Roadmap for Indonesia's Power Sector:
How Renewable Energy Can Power Java-Bali and Sumatra

Table of Contents

List of Figures

List of Tables

IESR | A Roadmap for Indonesia's Power Sector:
How Renewable Energy Can Power Java-Bali and Sumatra

Executive Summary

A Roadmap for Indonesia's Power Sector: How Renewable Energy Can Power Java-Bali and Sumatra Summary for Policy Makers was produced by Monash University's Grid Innovation Hub partnering with the Australia Indonesia Centre, supported by Agora Energiewende and the Institute for Essential Services Reform (IESR). The study modelled different pathways for Indonesia's power system to reliably meet energy and climate targets for the period 2018 to 2027. The study focuses on Java-Bali and Sumatra where the majority of the population lives and about 90% of the electricity is consumed. The model assesses both the demand and supply dimensions of the power system.

Analysis was performed with the PLEXOS power system simulation and planning software system, which is widely used internationally for power sector analysis. The study identifies the impact of reduced demand on generation investment, utilisation and power system cost and assesses the impact of adding considerable shares of wind and solar capacity to the system.

Key Findings

- **The Ministry of Energy and Mineral Resources and utility PLN have continuously overestimated energy demand in Java-Bali and Sumatra.** If PLN continues with its current plans, there is likely to be an overbuild of 12.5GW of coal, gas and diesel, resulting in approximately US$12.7 billion in wasted investment. This would burden PLN's finances and eventually have to be covered by the Indonesian public.
- **The risk of lower than planned utilisation of thermal power plants may increase as demand projections are overestimated and as renewables become cheaper.** Once renewables are built, they produce electricity at almost zero marginal cost. This could result in additional losses for PLN, which is locked into long-term power purchase agreements with Independent Power Producers.
- **Java-Bali and Sumatra could reliably meet growing electricity demand in the next 10 years through a doubling of the share of renewable energy.** The cost of doubling the share of renewables through investment in wind and solar is comparable to the current high fossil-fuel pathway. Greenhouse gas emissions would be reduced by 36%. The development of renewables would bring important additional co-benefits, reduce negative health and environmental impacts and provide job opportunities throughout the country.
- **A high renewables scenario coupled with realistic energy savings would result in a cost saving of US$10 billion over ten years as compared with the current RUPTL plan** if the cost of capital and cost of technology is brought down in line with international prices. This would require an ambitious long-term strategic plan, clear intermediate targets and implementing regulations in place.
- **Even with 43% renewables, the security of supply of the power system is maintained.**

Recommendations

To develop a reliable, cost-effective energy system which avoids wasted capital and serious environmental impacts, MEMR and PLN should:

- Review best practice approaches and techniques in demand forecasting around the world and implement such an approach in Indonesia;
- Integrate the potential of energy efficiency for forecasting future electricity demand;
- Review current proposals for new coal-fired power stations in the Java-Bali and Sumatra systems and apply current prevailing costs for renewable technology in developing future plans to asses alternative cost-effective and low carbon pathways;
- Develop and assess alternative scenarios and low carbon electricity pathways in the National Electricity Plan (RUKN) which integrate medium and higher renewable energy penetration in various electricity systems; and
- Adopt an ambitious long-term strategic plan with clear intermediate targets for renewable energy expansion, supporting policies and streamlined implementation at national, provincial and local levels.

photo: Sidrap Wind Farm / Biro Pers Istana

Introduction

This report has been prepared by Monash University's Grid Innovation Hub and the Australia Indonesia Centre for the Institute for Essential Services Reform (IESR). The work and report have been prepared and performed in collaboration with Agora Energiewende and Apogee Energy. Its purpose is to examine opportunities to reduce the carbon dioxide emissions of the electricity sector in Indonesia's main islands of Java, Bali and Sumatra, primarily by building renewable generation and reducing investment in coal and gas-fired generation. The underlying assumptions about the existing power system used for this analysis are based upon the annual planning report (RUPTL 2018) done by PT Perusahaan Listrik Negara (PLN), Indonesia's national electricity utility. More specifically this report shows that there are alternatives to the existing generation expansion plans for Indonesia that do not rely upon fossil-fuelled power stations, that can be built economically and satisfy the criteria of:

- Reliability, and in particular ensuring that there is not a deterioration in the amount of unserved energy (i.e. no increase in customer outages);
- Minimising system-wide cost;
- Equity to ensure that as many Indonesians as possible can enjoy access to electricity and the improvements in health and well-being that come with reliable electricity; and
- Meeting the Paris Climate Agreement's objectives of keeping global warming to well below 2 degrees.

Firstly, we have reviewed the energy and demand forecasts from the 2018 RUPTL which are from 2018 to 2027 inclusive. Analysis in the section titled 'Energy Demand' suggests that PLN's RUPTL forecasts are consistently above realised demand growth. This may explain the recent appearance of a high reserve margin in the Java-Bali system, resulting in unnecessary debt burden for Indonesia, ultimately paid for by the Indonesian taxpayer. To explore the impacts of over-forecasting we have developed and analysed alternative scenarios that are more conservative than those presented in the 2018 RUPTL. The demand growth scenarios we developed are more moderate than those used in the RUPTL based on the following logic:

- Much of the industrial growth relies upon the successful development of large individual industrial projects. As PLN is currently expected to incorporate demand forecasts based on all connection interest it receives this results in an industrial segment forecast that is overly optimistic. Many of these are unlikely to materialise in practice and we adjusted the forecast for this eventuality.
- The RUPTL currently does not take sufficient account of improvements in energy efficiency in household or commercial businesses which we would expect with more efficient appliances.

By modelling a realistic demand growth scenario we can demonstrate that generation investment that takes place in anticipation of unrealistic future growth means additional costs to the Indonesian community through stranded generation assets.

Currently, the Indonesian electricity sector is highly reliant upon fossil fuels for electricity production, in particularly on lignite and bituminous coal. As Indonesia is a major global coal exporter and has significant natural gas reserves, the domestic coal market and therefore coal prices in particular are linked to global market prices. This could also occur with natural gas if significant export capacity is developed. Hence not only do climate mitigation imperatives suggest renewables should be prioritised but renewables which are not impacted by any commodity price volatility can provide a financial hedge against this future uncertainty. Furthermore, the cost of renewables has fallen significantly globally and is expected to continue declining. In particular the costs for large scale wind and solar installations has declined to levels competitive with latest fossil fuel (coal and gas) generation. For instance, the International Energy Agency in its World Energy Outlook 2018 expects 25% of new generation built now to be renewable and 40% to be built as renewables by 2040.

With these global trends showing solar and wind are now competitive there is significant interest in Indonesia in renewable energy. We therefore investigate the economic and operational benefits and consequences of a power generation mix with significantly higher shares of wind and solar PV.

photo: Kupang Solar Farm / jabartoday.com

[1] https://webstore.iea.org/download/summary/190?fileName=English-WEO-2018-ES.pdf

Model Overview

We have used Energy Exemplar's PLEXOS version 7.50 to create a model of the Indonesian power system at a provincial level. The PLN identifies 34 provinces within Indonesia and three regions. Whilst our model covers all three regions and their contained provinces, our focus is on the interconnected Java-Bali and Sumatran systems which have the majority of the population and approximately 90% of the energy consumption. The provinces within each of these two regions are interconnected and there are plans to connect Sumatra and Java in the future, whilst the remaining provinces are mostly small and often represent isolated islands. The regions identified are as follows:

- Java – Bali
- Sumatra
- Eastern Indonesia

Figure 1 Identification of Indonesian regions

Within the modelling study's regions, we have the following provinces as follows:

Table 1 Java-Bali and Sumatra Provinces in the Model

Java – Bali Provinces	Sumatra Provinces
DKI Jakarta	Aceh
West Java	North Sumatra
Central Java	West Sumatra
Yogyakarta	Riau
East Java	Jambi
Banten	South Sumatera
Bali	Bengkulu
	Lampung

Our model has an hourly time series for the period 2018 to 2027, inclusive, for each province and our initial modelling uses the assumptions from the 2018 RUPTL with regard to existing and – for the business as usual (BAU) scenario – planned generator builds, as well as the energy and peak-demand growth. PLEXOS then models the investment and operation of generation in the model using an optimisation algorithm that minimises total system cost (capital investment plus operational costs). We then tested alternative credible scenarios to examine the impact of less energy consumption growth and greater use of renewable energy to measure the impact on system cost and CO2 emissions. These alternative scenarios cover the Java-Bali and Sumatra systems only, which together account for around 90% of overall Indonesian demand.

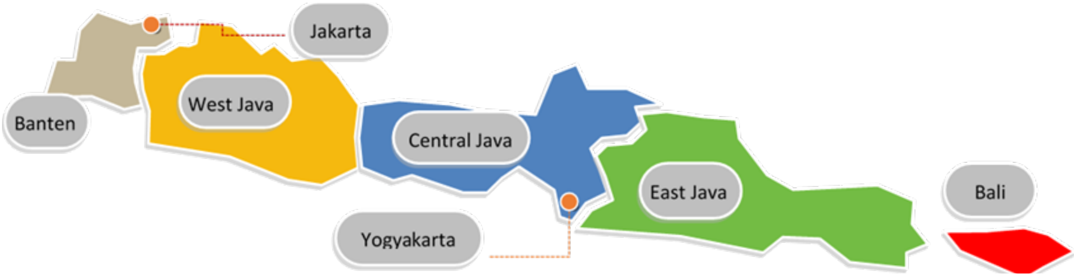


Figure 2 Simplified schematic of provinces within the Java-Bali system

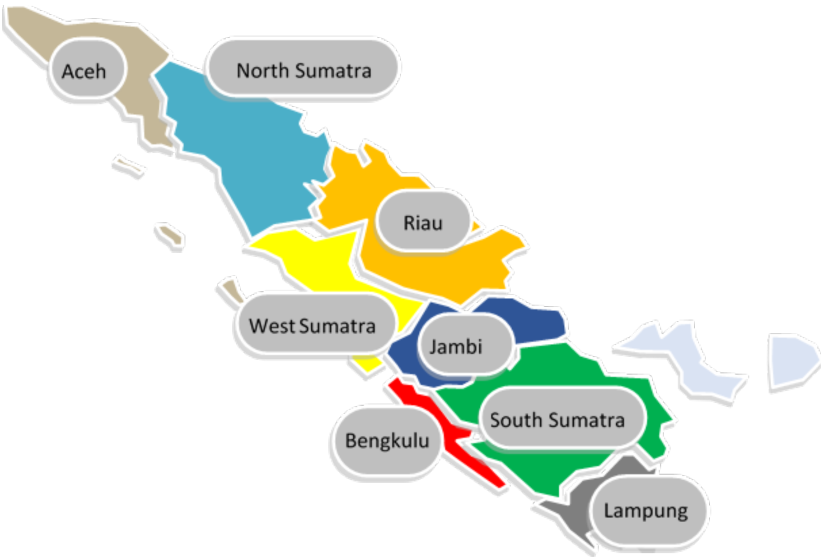


Figure 3 Simplified schematic of provinces within the Sumatra system

The Energy System Model

Much of the modelling of electricity systems and markets around the world as well as the Australian National Electricity Market (NEM) has been conducted using a commercially available electricity market simulation platform known as PLEXOS provided by Energy Exemplar (www.energyexemplar.com). This software translates the technical and microeconomic parameters of key power system components (generators, transmission lines, loads) into a single optimisation problem and then solves it. It can therefore be used by a range of users with varying degrees of sophistication.

PLEXOS is a mature and well-respected modelling package which is currently in use in similar modelling-related research, including modelling the impact of electric vehicles on Ireland's electricity market. Furthermore, PLEXOS can provide a highly accurate prediction of prices and has been used to model market behaviour following the introduction of carbon prices.

PLEXOS' least cost expansion algorithm and planning tools, as used in this study and by the independent Australian Energy Market Operator, AEMO, provides the optimal generation capacity mix given the current and forecasted policy constraints.

More detail about PLEXOS is available in Appendix A. In short, PLEXOS breaks down the simulation of an energy system into a number of phases which range in temporal scale and level precision. These time-scales range from: multiyear generation and transmission expansion planning, generation maintenance and unit commitment planning over a yearly horizon and operational optimisation down to hourly, 30-minute, or finer dispatch resolutions incorporating transmission flow constraints. It calculates locational marginal costs to determine time and location, specific values of generation and storage sources. Table 2 provides an overview of how and why PLEXOS is used in this study.

Table 2 PLEXOS key functionalities

Functionality	Features	How it is used
Regional demand and generation-based modelling	Model able to differentiate between regional variation in demand levels and marginal production costs	Model is set up for different demand profiles at hourly resolutions for each province in Java-Bali and Sumatra
Network transmission modelling with congestion and locational price signals	Transmission capacity limits are imposed allowing regional differentiation of marginal avoided cost which creates locational investment signals	Transmission interconnection with thermal limits is modelled between all regions/provinces and
Operational optimisation	Simulates the most precise version of power system operation possible with a given set of data inputs.	The model jointly tackles operation and investment decisions. We use the model to find the least cost and maximum reliability mix of investments then jointly minimises investment and operational costs.
Generation investment	Determines the best combination and timing of generators to be built based on a range of characteristics including build cost, fuel cost, renewable output forecasts for solar and wind, and many others.	

Multi-Island System Modelling Logic

In this study we always consider the entire system as one due to the assumption that in 2023 the two islands of Java and Sumatra will be connected by a 3000 MW transmission line. This connection allows for optimal investment decision solutions between the two islands, particularly in the case of wind and solar PV.

[2] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

System Model and Assumptions

This section describes the details of the system model that include the existing and future generation fleet, generator technical parameters, demand growth assumptions, and transmission system. In particular, it also focuses on renewable energy resource potential with particular attention paid to solar and wind resources as these are expected to dominate future electricity systems around the world.

Generation

We have examined PLN's 2018 RUPTL to determine the existing fleet of generators as well as their committed and planned power stations. All of our models have assumed that the following generation portfolios were installed before the beginning of 2018.

Table 3 - Provincial Generation Capacities by Generation Technology 2018

Generation Technology per Province 2018	Biogas	Biomass	Coal	Diesel & Fuel Oil	Gas	Geothermal	Hydro	PV	Waste	Wind	Total
Bali	-	-	426	263	357	-	-	-	-	1	1047
Banten	-	-	6201	-	740	-	6	-	-	-	6947
Central Java	-	-	5690	62	1034	60	306	-	-	-	7152
East Java	-	-	6770	25	2855	-	276	-	-	-	9926
Jakarta	-	-	-	2799	134	-	-	-	-	-	4139
West Java	-	-	2700	1158	1294	1199	2013	-	10	-	8374
Total Java	-	-	21787	4307	762	1259	2601	-	10	1	37585
Aceh	-	-	220	98	435	-	20	-	-	-	773
Bengkulu	-	-	-	39	-	-	253	-	-	-	292
Jambi	-	-	12	10	392	-	-	-	-	-	414
Lampung	-	-	454	-	160	210	230	-	-	-	1054
North Sumatra	2	-	1000	271	1320	460	534	-	-	-	3587
Riau	-	-	234	279	465	-	114	-	-	-	1092
South Sumatra	-	-	1277	25	864	-	134	1	-	-	2301
West Sumatra	-	-	407	9	54	-	302	-	-	-	772
Total Sumatra	2	-	3604	731	3690	670	1587	1	-	-	10285
TOTAL	4	33	25513	5307	11385	1929	4188	1	10	1	48371

Generation retirement

Based on consultation with stakeholders, we were notified of intended retirements of large generators by PLN. These retirements relate only to Java-Bali and no information was available about planned retirements in Sumatra at the time the study was performed; therefore, for Sumatra, no retirements were incorporated in the model. Even if some plants may retire during the next decade, this will not substantially affect the main outputs of the analyses.

The timing of the retirement is in fact somewhat uncertain. For modelling purposes, we staged the retirements in equal portions from 2024 to 2026. The planned retirement of plants is represented in the model as follows:

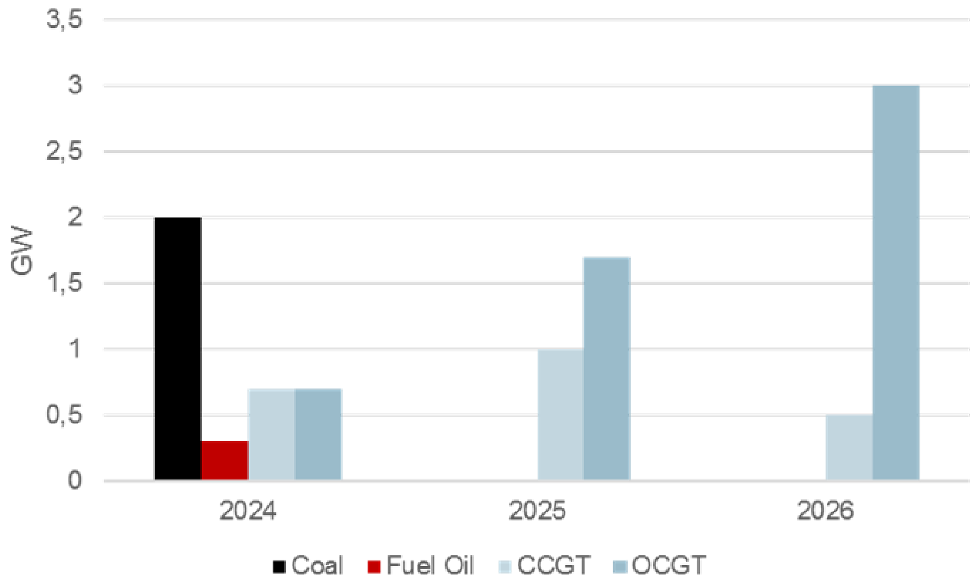


Figure 4 Retirement of power plants per year

Renewable Energy Generation Data

To represent hourly generation profiles of wind and solar in Sumatra and Java-Bali we utilised the resources of Renewables.Ninja . Renewables.Ninja provides hourly power output data from wind and solar power plants located anywhere in the world. It is based on NASA MERRA data and Surface Solar Radiation Data Set Heliosat (SARAH) data, and widely used in academia and project development, whenever no more detailed local data is available. Four profiles for each of solar and wind across both interconnected systems were chosen and these were used as a generic input to the model. Different profiles were chosen to ensure that our data had:

- Geographic diversity
- Captured variability due to different local weather and cloud conditions
- Wind sites were in suitably windy locations (i.e. mainly coastal and >25% capacity factor)

There are many factors that limit the availability of suitable wind and solar generators including:

- Land availability
- Proximity to the electricity transmission and distribution network
- Suitably high wind speeds and consistency of wind for wind generators
- Impacts on native flora and fauna
- Adequate insolation for solar farms, although this is generally sufficient across Indonesia due to the high number of hours of daylight and minimal cloud cover

Wind and solar generators are classed as variable as they depend upon the availability of wind energy and sunshine respectively which varies according to local weather conditions and the time of day.

[3] https://www.renewables.ninja/; for details see: Pfenninger, Stefan and Staffell, Iain (2016). Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, pp. 1251-1265. doi: 10.1016/j.energy.2016.08.060; Staffell, Iain and Pfenninger, Stefan (2016). Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output. Energy 114, pp. 1224-1239. doi: 10.1016/j.energy.2016.08.068

Renewable Potential

In order to model the economics of investments in renewable energy an estimate of resource availability is required. In this study we focussed on wind and solar PV. In the past, solar resources, and in particular wind resources in Indonesia were often considered rather limited; however, in newer analysis from the Government of Indonesia cited below, we see that there is significantly more potential than was previously estimated. A more thorough assessment which takes into account more efficient technologies for wind turbines operating at a higher range of speeds (both low and high) has been developed. This has largely been due to the increase in the size of turbines, the rotor diameter and the hub height which have improved capacity factors globally, thereby making more sites suitable economically suitable in Indonesia as well.

Table 4 Solar and Wind Resources Potential Across Indonesia

	Total Indonesia	Total Java Bali	Total Sumatra	Total Eastern Indonesia
Wind	**60700**	24000	13400	23300
Solar	**207900**	33100	93700	81100

Sourced from Totals from *"ESDM Energy Outlook 2016"*[4], and
"Peluang investasi dan potensi pengembangan Energi Baru Terbarukan Indonesia"[5].

The regional level of potential renewable generation was broken down as follows for Java- Bali and Sumatra:

Table 5 Provincial Potential Solar and Wind Capacities - Java Bali

Region	Wind (MW)	Solar (MW)
West Java/Banten	8800	11600
Jakarta	0	200
East Java	7900	10300
Central Java	6300	9700
Bali	1000	1300

Table 6 Provincial Potential Solar and Wind Capacities - Sumatra

Region	Wind (MW)	Solar (MW)
South Sumatra	1213	18903
Jambi	440	6850
Bengkulu	247	3846
Lampung	1100	2200
West Sumatra	400	5900
Riau	900	8500
North Sumatra	400	11900
Aceh	900	7900

4 ESDM Energy Outlook 2016

5 Peluang investasi dan potensi pengembangan Energi Baru Terbarukan Indonesia, Berdasarkan Peraturan Menteri ESDM Nomor 12 Tahun 2017, tentang Pemanfaatan Sumber Energi Terbarukan untuk Penyediaan Tenaga Listrik, Jakarta | 20 Februari

The breakdown into regions was estimated in proportion to regional energy use. In the absence of better data this was considered to be the best proxy based on the logic that in Java-Bali and Sumatra resources are proportional to land area which is roughly correlated with population and therefore energy use. Although very rough, this helps avoid intricate assessment of inter-province transmission capacity which is beyond the scope of this study. The investment model takes these as the absolute maximum possible installed capacity for each technology for each region.

Solar Resources

Four solar locations were chosen to represent a diversity of solar profiles and to include the difference in solar output times from east to west i.e. that the local solar production is matched to the local demand in each of the time zones in Java-Bali and Sumatra. There were three sites chosen for Java-Bali and one for Sumatra (with Sumatra being oriented north-south). We reviewed the solar resource from Solargis website.

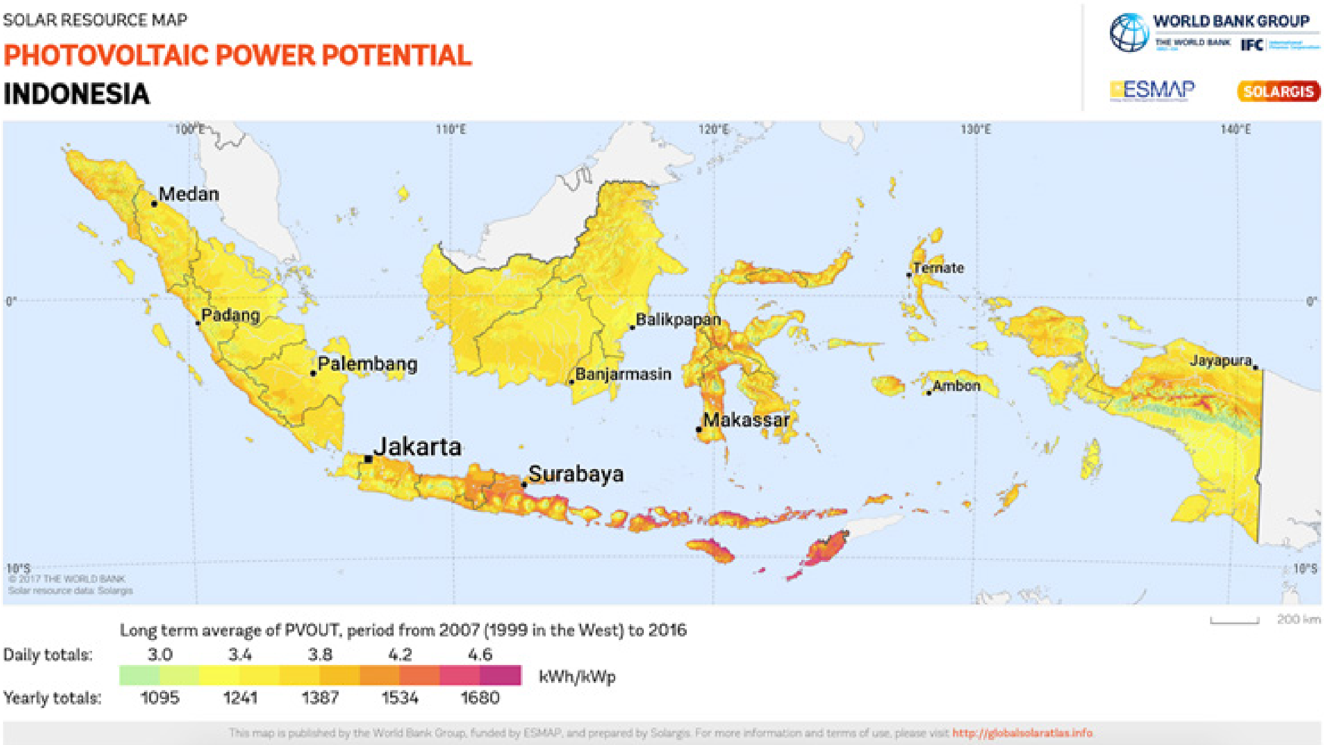


Figure 5 SolarGIS map of Indonesian Solar Resource

We used Renewables. Ninja to select sites that were located in each region of interest to provide an hourly trace over a calendar year. Once a suitable site was selected, a year of data was randomly chosen from 2014, 2015 or 2016. The year itself was chosen at random to be different for each site to ensure diversity in the profiles that may not exist in the interpolation of solar profiles from the Renewables.Ninja model. Figure 6 shows a representative profile from the first week in January for the hourly outputs.

[6] https://solargis.com/maps-and-gis-data/download/indonesia

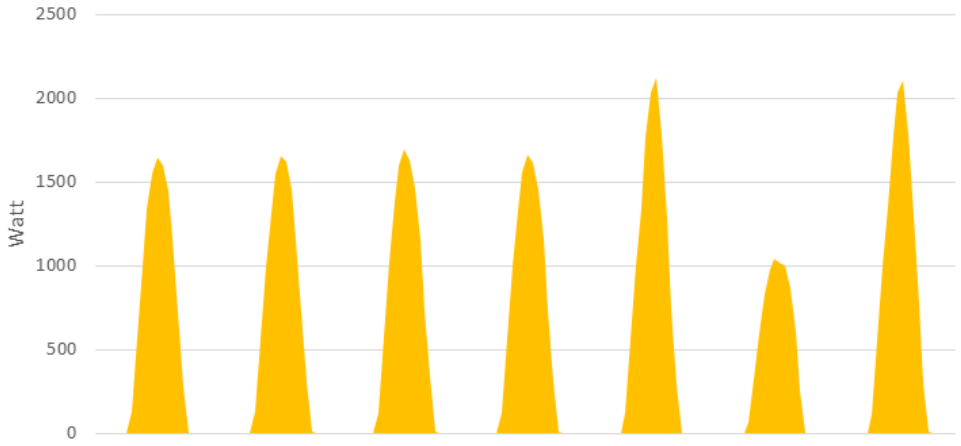


Figure 6 Representative solar profile AC System Output (W) - January 1 -7

The following descriptions detail the regions chosen for suitable prospective solar sites for the model.

Table 7 Samples of Solar Sites and Capacity Factor

Region	Capacity Factor
Eastern Java and Bali	15.8%
Central Java	15.3%
Banten	14.6%
West Sumatra	12.8 %

Wind Resources

Wind is a significant source of electricity generation globally and there is opportunity within Indonesia to build wind farms. Whilst many parts of Indonesia are unsuitable for wind farms due to limited availability of land due to urbanisation or areas of environmental sensitivity, or low wind speeds, review of meso-scale modelling finds there are more suitable locations then often anticipated. The following diagram from WindPRO Denmark shows average wind speeds as an initial guide to the suitability of particular locations.

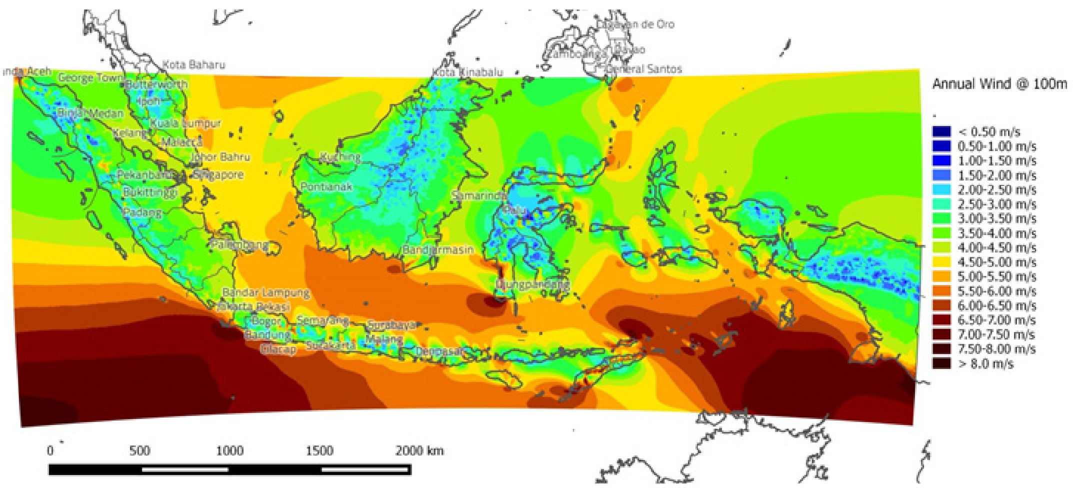


Figure 7 Wind Resource Map (Danish Energy Agency)

7 http://help.emd.dk/mediawiki/images/3/30/Indonesia100m.jpg

Wind data sourced from WindPRO Denmark wind locations are only assumed to be 6.0m/s above for suitable geographic provinces.

Using the WindPRO assessment as a guide, sites were examined using Renewables.Ninja to retrieve a year's worth of data which was randomly chosen from 2014, 2015 or 2016 to construct a representative profile. Each site was assumed to be a representative 100MW wind farm utilising a 100m hub height, 3.0MW 112m diameter Vestas turbines. The output data was then normalised so wind farms can be scaled appropriately within the model as a function of their rated capacity.

Table 8 Samples of Wind sites and capacity factor

Region	Capacity Factor
West Java	33.4%
East Java	25.3%
South Sumatra	24.5%
North Sumatra	27.7 %

Geothermal

Indonesia has one of the best geothermal opportunities globally as it is one of the countries on the "ring of fire" on the Pacific tectonic plate. Currently, it has 1925 MW of geothermal installed making it the second largest after the USA for installed geothermal plant[8].

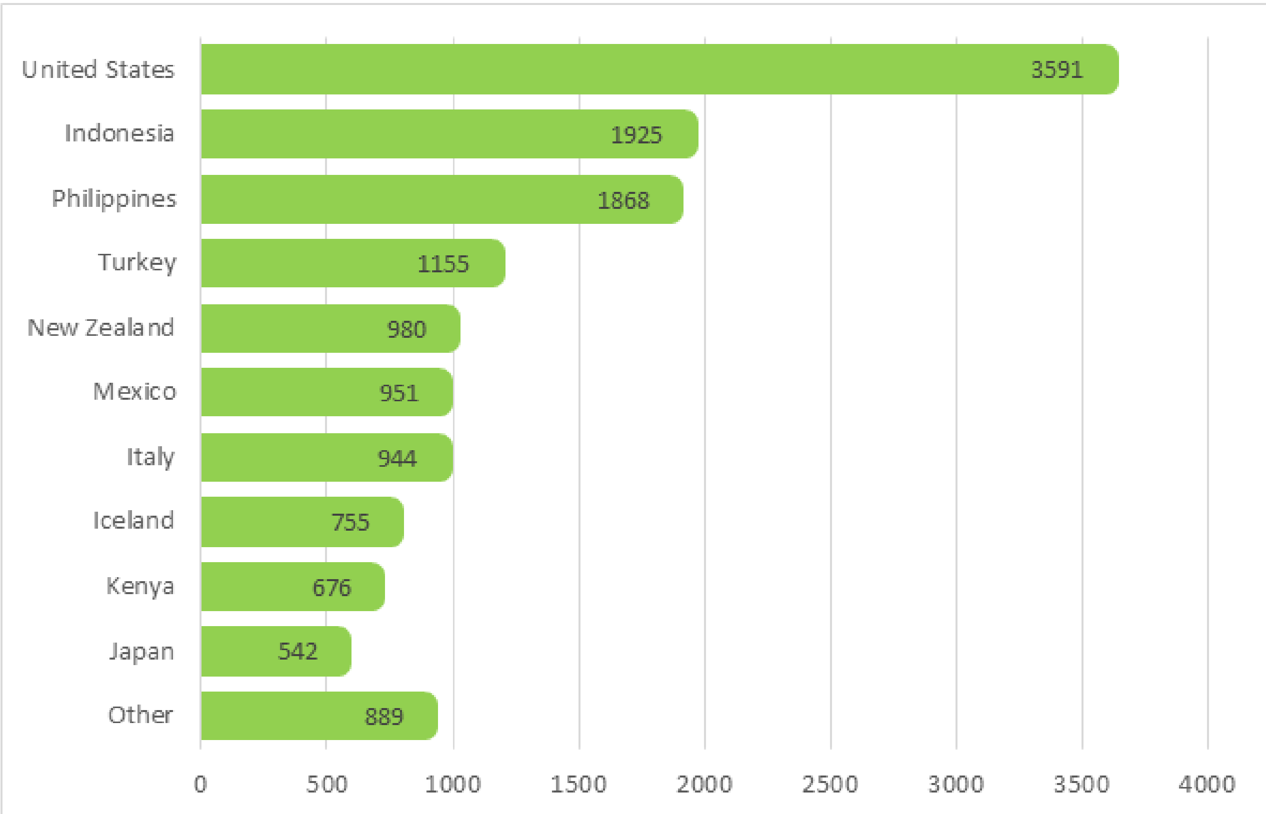


Figure 8 Top 10 Countries for Geothermal Potential. Source: TGE Research (2018)

[8] http://www.thinkgeoenergy.com/indonesia-reaches-1925-mw-installed-geothermal-power-generation-capacity/

The RUPTL 2018 details plans for more than an additional 4000 MW until 2027; there is potential resources for as much as 11,073 MW to be developed according to ThinkGeoEnergy10.

Within the model it is assumed that geothermal plant runs 24 hours a day except for maintenance as its marginal cost is close to zero and because there is no effective constraint on the amount of energy available. It would be anticipated that these units would be at close to maximum power for most of their operation except when there is a need to reduce total generation.

In all scenarios we have included existing geothermal plant as well as future plant as only those identified within the RUPTL.

Hydro-electric Power

When modelling hydro-electric generation we identify generating plant as one of the following types:

- Hydro generation – Indonesia currently includes a range of both hydro with reservoirs and run of river. The hydropower plants excluded micro-hydro and included an assumption that hydro plants are built in line with environmental and social standards, which are more likely for a smaller hydro project. We assume that the hydro-electric generation is affected by seasonal inflows and mostly generate when demand and value of water is highest.
- Pumped storage – hydro generation which pumps energy from a base storage dam to a higher reservoir and then later uses the water to generate electricity when needed. This is a form of storage. However it is a net consumer of electricity due to energy losses in this process and the pumping required to facilitate later electricity generation and this is modelled within the study.

To estimate the amount of energy available for hydro generation that is not pumped hydro we established the historic capacity factor of hydro generation in Indonesia. To do this we reviewed the 2016 Hydropower Status Report[9] which showed for Indonesia a production of 13,741 GWh and 5258 MW of installed capacity giving an annual capacity factor of 30%, meaning that on average, a hydro plant is able to generate only 30% of its nominal power.

As hydro inflows are not usually consistent, as rainfall varies from day to day and month to month, we have taken a suitable proxy for inflows as the average monthly rainfall for Jakarta to create a monthly energy capacity. The following chart[10] represents the average monthly rainfall for Jakarta used and subsequently, the maximum available monthly capacity when it is converted to an energy estimate.

[9] 2016 Hydropower Status Report, International Hydropower Association
[10] https://en.wikipedia.org/wiki/Jakarta

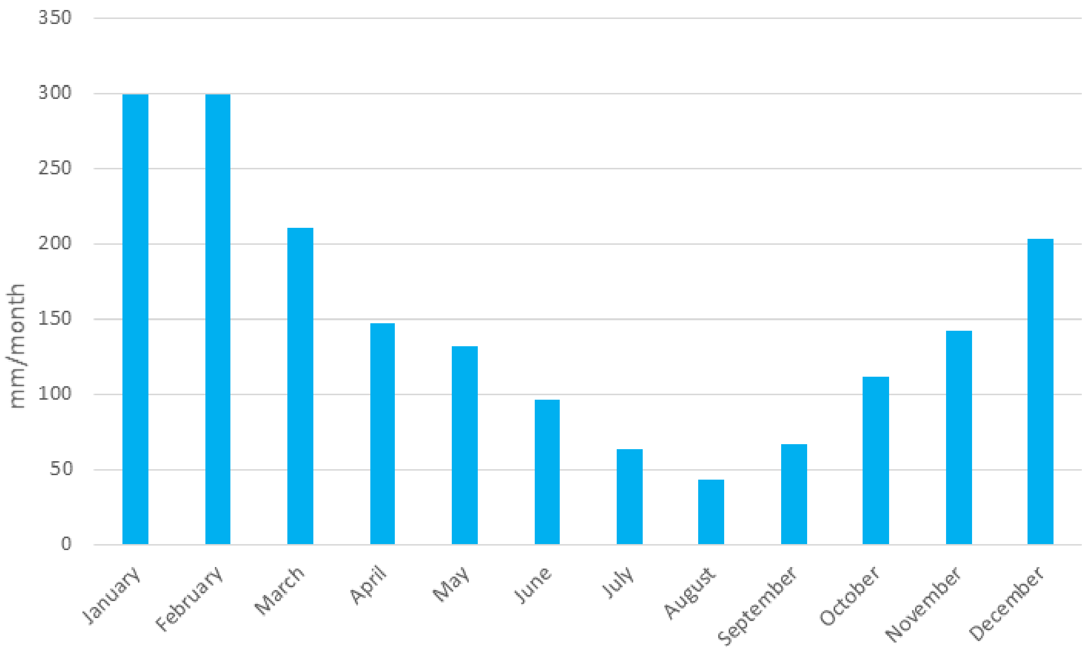


Figure 9 Monthly Jakarta rainfall averages

Transmission Infrastructure

Understanding and fully modelling the intricacies of electrical behaviour of the transmission network is a highly involved process that is beyond the scope of studies such as this. A simplified approach is usually used in which power transfer limits are assumed between major parts of the electricity network that roughly correspond to major load areas and major generation zones. In the case of Indonesia these correspond to Java-Bali and Sumatra provinces. These transfer limits are a function of the physical capacities of transmission lines (usually based on thermal overload limits) and on dynamic limits. These dynamic limits are contingent upon many factors and usually related to keeping the system in a secure state to prevent frequency or voltage instability in the case of the failure of a large system component such as a transmission line or large generating unit. Our model therefore includes maximum and minimum transfer limits between connected provinces and also includes an assumed interconnection between Sumatra and Java-Bali from 2023.

In each province, we have identified through a range of sources including the RUPTL and stakeholder and expert workshops the transfer capacities at present and for the horizon covered in the RUPTL. The following tables show the modelled limits within our model for Java-Bali and Sumatra. We also show the planned interconnection between the two systems which was estimated to operate from 2023. Note that while there are no clearly specified plans in the RUPTL for transmission expansion within Java-Bali and Sumatra we analysed flows and congestion patterns and determined reasonable expansions.

Expansion of Grid

We assumed that all the smaller transmission lines increased by a factor of 1.5 in 2023 which is mid-way through the investment horizon.

Java-Bali and Sumatra Inter-province Transfer Limits

The model includes details of transmission transfer limits between the different provinces. It should be noted that the Java grid is a reasonably tightly interconnected system, so the transfer limits are essentially notional capacities that in similar models typically capture a range of transmission-related constraints such as thermal limits as well as voltage and transient stability limits.

The limits were sourced through discussions with various Indonesian electricity sector experts and through analysis of multiple general reports about the Indonesian grids. There is no independent public source for this data that we can directly reference. The RUPTL does not provide this level of detail.

Table 9 Interconnector limits within Java-Bali

Region From: / To:	Jakarta	Yogyakarta	East Java	West Java	Banten	Bali	Central Java
Jakarta		-	-	10,000	10,000	-	-
Yogyakarta	-		-	-	-	-	10,000
East Java	-	-		-	-	400 2,000^{2020}	4,200 6,300^{2023}
West Java	4,000 6,000^{2023}	-	-		4,000 (6,000)^{2023}	-	4,200 6,300^{2023}
Banten	10,000	-	-	10,000		-	-
Bali	-	-	400 2,000^{2020}	-	-		-
Central Java	-	10,000	4,200 6,300^{2023}	4,200 6,300^{2023}	-	-	

Table 10 Interconnector limits within Sumatra

Region From: / To:	Aceh	North Sumatra	West Sumatra	Riau	Jambi	South Sumatra	Bengkulu	Lampung
Aceh		2,500 3,750^{2023}	-	-	-	-	-	-
North Sumatra	2,500 3,750^{2023}		-	400 600^{2023}	-	-	-	-
West Sumatra	-	-		2,500 3,750^{2023}	544 816^{2023}	-	-	-
Riau	-	400 600^{2023}	2,500 3,750^{2023}		2,000 3,000^{2023}	-	-	-
Jambi	-	-	544 816^{2023}	2,000 3,000^{2023}		-	-	-
South Sumatra	-	-	-	-	-		500 750^{2023}	1,500 2,250^{2023}
Bengkulu	-	-	-	-	-	500 750^{2023}		-
Lampung	-	-	-	-	-	1,500 2,250^{2023}	-	

Table 11 Interconnector between Java and Sumatra

	Java-Bali (Banten)	Sumatra (South Sumatra)
Java-Bali (Banten)		3000^{2024}
Sumatra (South Sumatra)	3000^{2024}	

Energy Demand

This section sets out the assumptions behind the demand growth scenarios developed for our model. This includes the revised annual energy and peak demand scenarios and how these translated into hourly demand profiles to be used in the simulations.

Annual Energy Demand

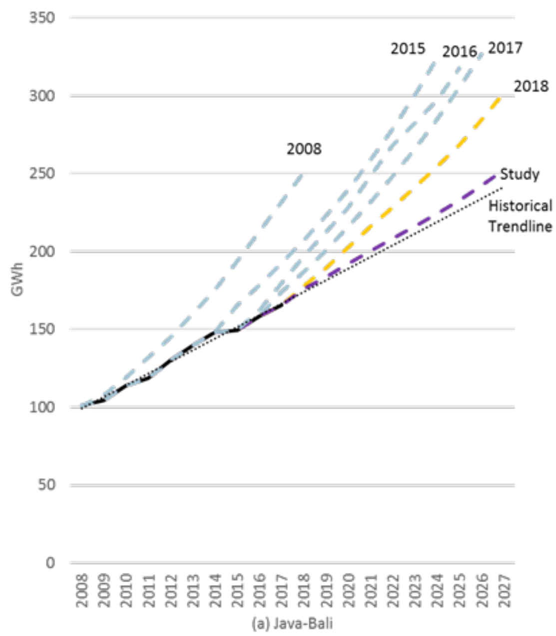
The PLN's RUPTL has identified annual energy consumption in each province by four different categories:

- Residential – households
- Commercial – private businesses
- Industrial – large business loads, mining or large industrial processes
- Public – government sector, street lighting etc.

These annual totals by province by category and province sourced from the RUPTL are detailed in Appendix 2. They are reflected in the baseline demand scenario, which represents the demand and supply values for 2027 as identified in the RUPTL

Assessing future demand growth is a challenging endeavour. In many cases, demand projections are driven by political targets, e.g. on GDP developments. Also, very often, energy efficiency potential is not adequately reflected. Therefore, in many growth projections in particular of emerging economies, demand growth assumptions tend to be higher than actual growth observed.

This is also the case for Indonesia. Using the previous RUPTL reports from 2008, 2015, 2016 and 2017 as well as the 2018 RUPTL and comparing these against actual consumption figures in each of Java-Bali and Sumatra we can observe a trend of forecasts that are rarely met or exceeded. These results are displayed in the following charts for each of the two regions.



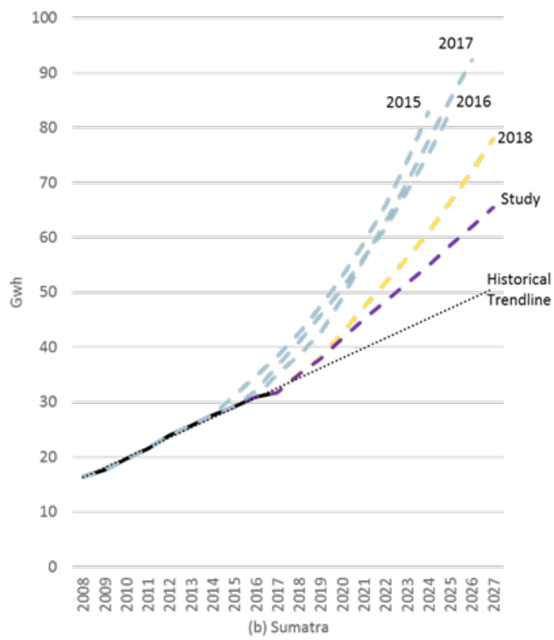


Figure 10 Java Bali and Sumatra RUPTL forecasts versus actuals

In order to identify the impact of lower demand growth on power system cost and in particular utilisation of power plants that have been constructed based on the assumptions of higher demand, we defined an alternative scenario for each province based upon the following assumptions as compared to the RUPTL's original forecast:

1. Industrial loads growth is only half of what is expected in RUPTL (e.g. instead of a 10% annual growth a 5% annual growth would be assumed)
2. In the residential sector two competing trends need to be modelled. With customer numbers increasing we also model a per household energy intensity reduction target of 10% by 2027. A simplifying assumption needed to be made to avoid needless complexity which could arise due to current variation in energy intensity across regions and in the RUPTL forecasts. Analysis showed that a good approximation is achieved by computing the projected 2027 energy for the residential sector fully for each province but then linearly interpolate demand in the intervening years.
3. As in the case of the residential sector, we assumed energy intensity for the commercial sector was 10% lower than in the RUPTL 2027 forecast. Again, in order to minimise complexity, we computed the 2027 commercial demand for each province and linearly interpolated between 2018 and 2027 to determine demand in the intervening years.
4. Public load forecasts remain unchanged.

When we compare historic growth in the most recent 5-year period between 2012 and 2017, against the RUPTL forecasts and our own forecasts, we have the following results as shown in table 13.

Table 12 Relative energy growth rate in the forecast versus historic trends

Region	Historical Data 2012-17	RUPTL (2018)2018-2027	Moderate Growth Scenario 2018-2027
Sumatra	5.8%	9.2%	7.2%
Java-Bali	4.9%	6.0%	4.1%
Total	5.0%	6.6%	4.6%

The relative differences between the growth scenarios can best be seen in the following charts of total energy growth by region in each consumption segment in the period 2018 to 2027. The charts below show the four major components of energy demand (Residential, Commercial, Industrial and Public use) in Java-Bali and Sumatra and how they change in the moderate growth scenario.

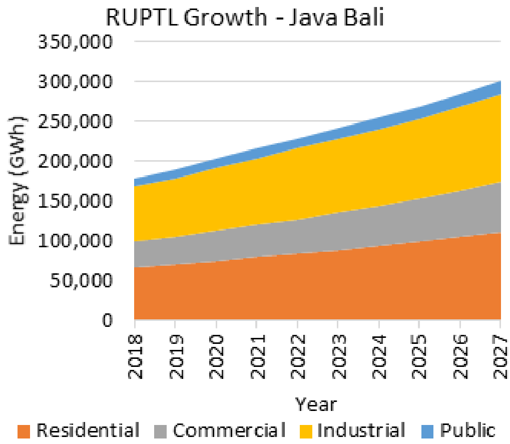


Figure 11 Growth in energy consumption by segment (RUPTL) - Java-Bali

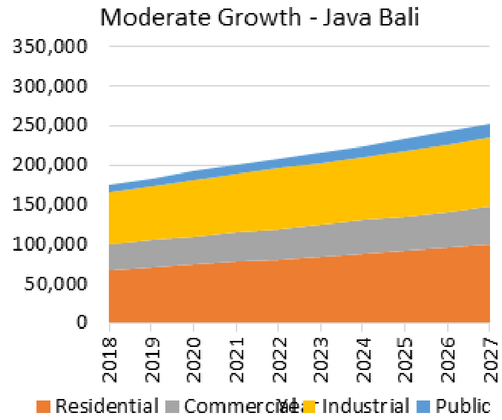


Figure 12 Growth in energy consumption by segment (Moderate growth) - Java-Bali

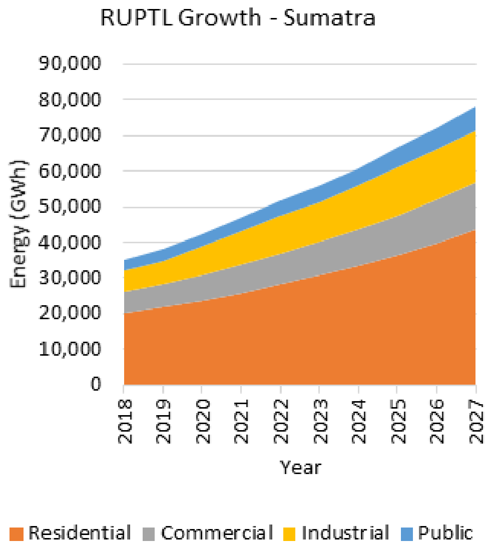


Figure 13 Growth in energy consumption by segment (RUPTL) – Sumatra

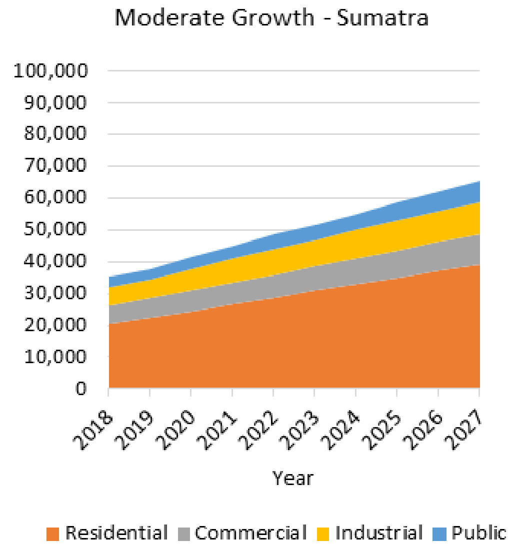


Figure 14 Growth in energy consumption by segment (Moderate growth) Sumatra

Peak demand growth

In more detailed studies when more demand data is available peak demand growth is often modelled separately to energy growth. They can grow at different rates as the load can become more or less peaky depending on how the different demand sectors growth (e.g. residential customers growing faster leads to peakier load shape while industrial load sector growing faster leads to a flatter load shape).

In this study we assumed that the growth is that same, implying that the load shape does not change over the horizon. At the level of accuracy of the various assumptions in this study this should not have a significant impact on modelling error. The growth of peak demand is shown in Figure 15. The combined Java-Bali-Sumatra peak demand in 2018 is around 34,940MW while in 2027 it grows 60,157MW in the RUPTL scenario and 49,322MW is the moderate growth scenario.

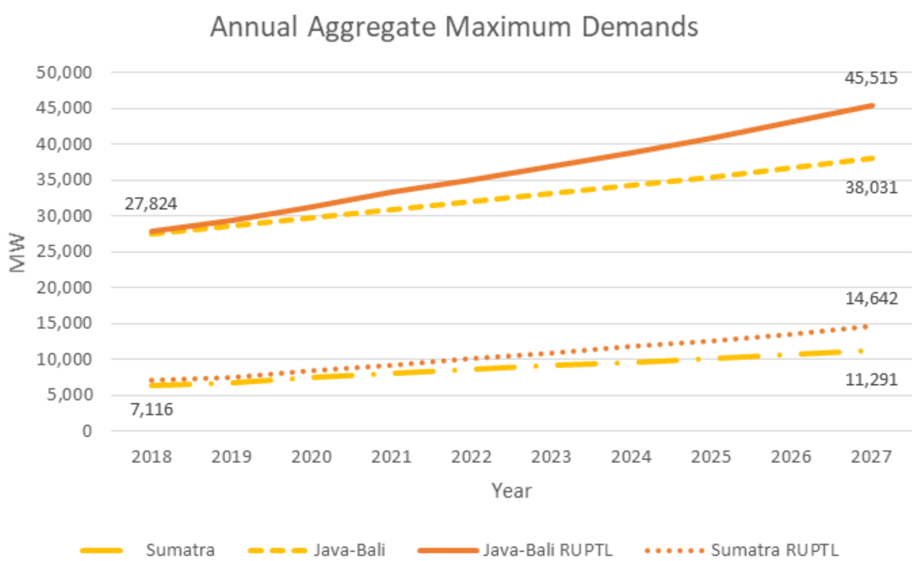


Figure 15: Peak demand growth in RUPTL and Moderate growth for Java-Bali and Sumatra

Commentary

It is noteworthy that for Sumatra demand growth is dominated by the residential sector's significant share, where it makes up more than half the energy consumption, whilst in Java-Bali, it is closer to one third of energy consumption, depending upon the comparison year. This means that the Java-Bali load is more influenced by changes in timing and cancellation of projects within the industrial sector growth trajectory than Sumatra. This relates to the discussion in the next section around demand profiles. Specifically, we note that the hourly demand shape in Java-Bali is somewhat flatter reflecting loads which run 24-7 and has higher levels of uncertainty as much of its growth is reliant upon confirmation that large demand projects are indeed built as per the RUPTL forecasts. Sumatra's greater share of residential load is also evident in the relationship between peak demand and average energy consumption, such that the load profile has higher relative peaks.

Hourly Demand Profiles

The modelling of the electricity sector is typically best conducted with either half-hourly or hourly demand profiles to account for how demand for energy changes during the day and the potential requirement for power stations with sufficiently fast ramp rate to satisfy changes in demand. Also, increasing levels of renewable generation and their correlation with energy demand during the day can be assessed so that economic levels of renewable generation can be built, and sufficient levels of fast start generation built if required.

We have previously sought a complete set of at least a year's worth of half-hourly data for the Java-Bali system but to date only about four single weeks in a year have been sourced, which is insufficient for our study. As a suitable substitute, further investigation revealed the availability of Malaysian half-hourly data from their market operator, Grid System Operator which we have used as a representative substitute. A screenshot of their data hub is displayed below.

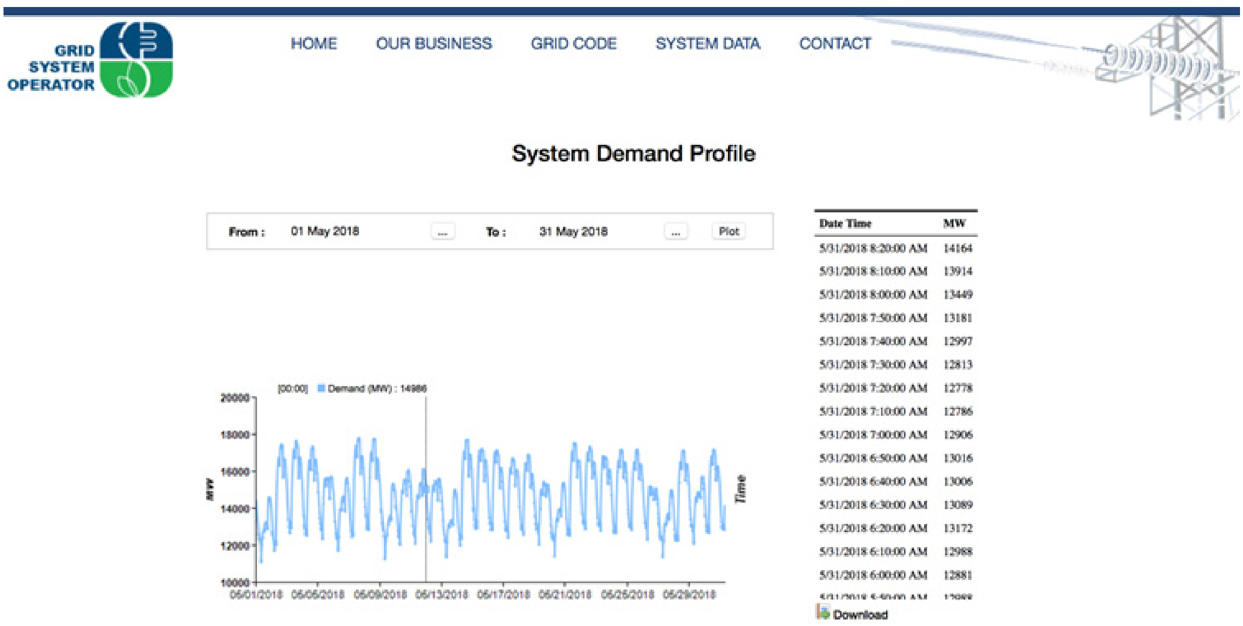


Figure 16 Grid System Operator (Malaysia)

[11] https://www.gso.org.my/LandingPage.aspx

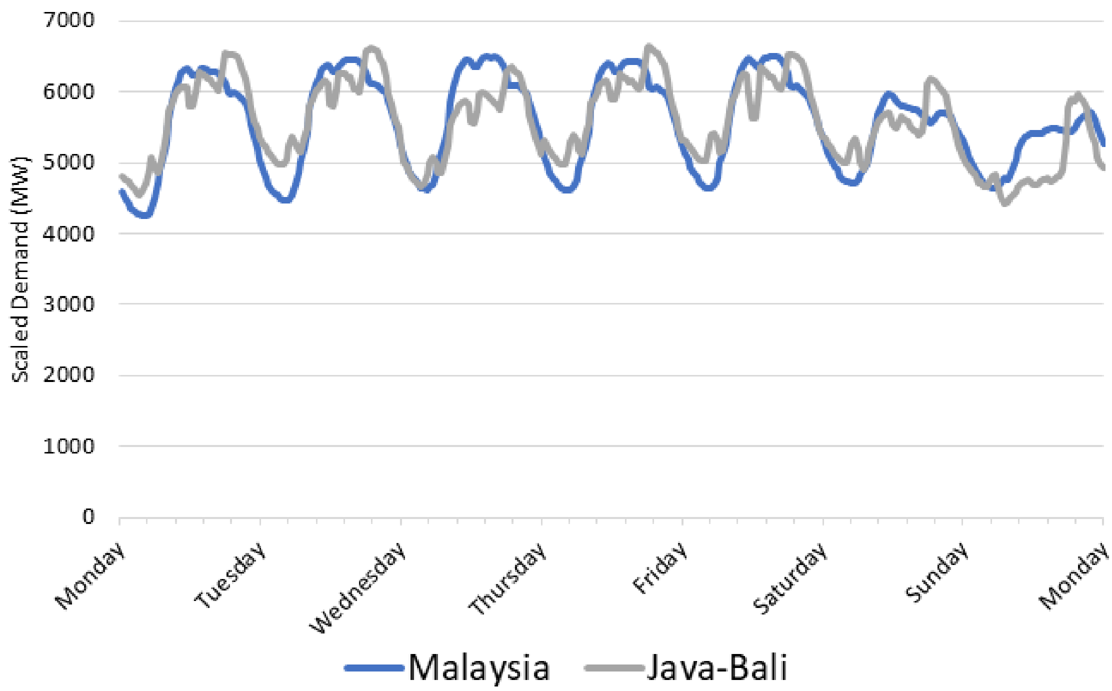


Figure 17 Java-Bali and Malaysia load profile comparison

While noting the two profiles are not exactly the same, the similarities in daily profiles and the weighting of consumption across weekdays, Saturday and Sunday are evident. The major difference we observe is the fact that there is a slightly higher evening peak in Java-Bali, while in Malaysia, the peak is during the day. However, as there are evening peaks in the Malaysian data in the weekend, these are then also present in the model. It is our view that these profiles are sufficiently similar that there would indiscernible differences in the modelling outcomes if and when the full Java-Bali data set becomes available.

Generation plant parameters

These parameters cover all the key technical and economic parameter pertaining to the operation of and construction of large-scale electricity generation plant.

These parameters are sourced from a range of studies in the Indonesian, European and Australian public domain, and include expert judgement by the researchers at Monash University and the Australia Indonesia Centre, as well as Agora Energiewende. The key sources are listed in the table below:

Table 13 Generation plants parameter

Publications	Source	Relevant quantities sourced
Technology Data for the Indonesian Power Sector – Catalogue for Generation and Storage of Electricity	Indonesian Secretariat General of the National Energy Council (DEN) and the Danish Energy Agency (2017)	CAPEX for coal and CCGT (OCGT is 80% of the CCGT cost); CAPEX for wind and solar in Energy Transition pathway
Asia Pacific LCOE Update	Bloomberg New Energy Finance (BNEF) (2017)	CAPEX for wind, solar, and geothermal
Indonesian Energy Technology Cost Assessment (IETA)	Australia Indonesia Centre, Australian National University and Monash University and University of Melbourne (2018)	Capex for Geothermal, Hydro
CSIRO GenCost 2018 Updated projections of electricity generation technology costs	The Commonwealth Scientific and Industrial Research Organisation (2018)	Cross checking all plant techno-economic parameters against current Australian State of the Art.
Australian National Transmission Network Development Plan 2027	Australian Energy Market operator	A range of generator technical parameters such as ramp rates and fossil fuels' CO_2 emission rates

Renewable Technology Costs and Build assumptions

This section sets out the construction costs of new generation plant used in the various scenarios in the study.

Technology transition pathways:

In this study there are two overall scenario pathways that we consider that reflect the consensus on the expected way that renewable technology deployment will take place. This impacts the following parameters:

- Technology build costs
- WACC

These pathways are described here:

1. Standard Technology Development pathway – This pathway represents the best estimate of the rate of change of cost in new technologies.
2. Energy Transition pathway – This is an optimistic estimate of technology development and also includes a lower WACC as it represents a world where investment in renewables in Indonesia is perceived as less risky (WACC of 8% versus 10%).

The construction costs are provided in the model in nominal terms and are sourced from a range of studies and combined based on expert experience. The main source is the Indonesia Technology Cost Assessment published by the National Energy Council and Danish aid agency DANIDA.

12 Dr Thomas Schlegl Fraunhofer ISE Dr Christoph Kost, "Stromgestehungskosten Erneuerbare Energien," May 15, 2018, 1–44.
13 Bjarne Bach, "Technology Data for the Indonesian Power Sector," December 18, 2017, 1–140.
14 Kaliapa Kalirajan and Arif Syed, "The Indonesian Energy Technology Assessment (Ieta) 2017," November 2, 2018, 1–165.

Table 14 Standard Technology Development Pathway: generator build cost by technology US$/kW

From Year					
Technology	2018	2019	2020	2025	
Biogas	$ 2,600				Costs (US$/kW)
Biomass	$ 3,200				
CCGT	$ 750				
Coal SC	$ 1,400				
Geothermal	$ 2,214				
Hydro	$ 2,200				
OCGT	$ 600				
Solar PV	$ 1,100	$ 1,000	$ 900	$ 800	
Wind	$ 1,930	$ 1,930	$ 1,650	$ 1,500	

Table 15 Standard Technology Development Pathway: generator build cost by technology US$/kW

From Year					
Technology	2018	2019	2020	2025	
Biogas	$ 2,600				Costs (US$/kW)
Biomass	$ 3,200				
CCGT	$ 930				
Coal SC	$ 2,000				
Geothermal	$ 2,214				
Hydro	$ 2,200				
OCGT	$ 740				
Solar PV	$ 1,100	$ 960	$ 830	$ 720	
Wind	$ 1,800	$ 1,650	$ 1,500	$ 1,400	

Financial Investment Parameters

The key financial investment parameter in this study is the WACC – Weighted Average Cost of Capital which represents the return to the investors, primarily equity and debt investors. In Indonesia the standard mix of debt versus equity for energy projects is considered to be a ratio of 80:20.

We consider a standard WACC of 10% for all technologies in our main scenarios. This is, for Renewables, above current values, but should be feasible in the future, if a stable regulatory framework is established and a larger portfolio of projects is being implemented successfully. In sensitivities, we look at alternative values of WACC as follows:

Table 16 WACC assumptions

		WACC	
Pathway	**Scenario driver**	**Technology**	**Value**
Standard technology development	Medium WACC	All Technologies	10%
Energy Transition / accelerated uptake of RES	Low WACC	Renewables and OCGT Other fossil generators	8% Not used
Slow uptake / high risk perception remaining about Solar and Wind	High Solar Wind WACC Medium Solar Wind WACC	Solar and Wind Other fossil generators	15% 10%

New Build Generator and economic life time

The sizes of candidate new build generators used in the model are set out below. The key points to note here are:

1. Thermal plant as well as Hydro and Geothermal candidates are the committed and planned generators from the RUPTL; the only exception is OCGT plants. We allow to build some more than was planned in the RUPTL (see below)
2. Generic new build plant is limited to Solar and Wind generic plant complemented by additional generic OCGT that is used in higher renewables scenarios to ensure reliability.

Table 17 New build renewable generator and economic lifetime

Technology	Unit Size (MW)	Economic Life (years)	Source
Wind	50	25	AEMO NTNDP 2017[2]
Solar	50	25	ibid
Hydro	RUPTL Candidates	25	ibid
Geothermal	RUPTL Candidates	25	ibid

Table 18 New build fossil generator and economic lifetime

Technology	Unit Size (MW)	Economic Life (years)	Source
Coal Super Critical	RUPTL Candidates	25	AEMO NTNDP 2017[2]
CCGT	RUPTL Candidates	25	ibid
OCGT	RUPTL Candidates	30	ibid
Generic OCGT	200	30	ibid
Diesel	RUPTL Candidates	25	ibid

Operational parameters

Heat rates, outage rates and other factors were modelled, where the following definitions apply:

Table 19 Definition of operating parameter

Parameter	Overview
Heat rate (GJ/MWh)	The amount of net energy produced for a given amount of energy consumption. i.e. the inverse of efficiency where (3.6/Heat Rate) = efficiency (%)
Variable Operation and Maintenance (Variable O&M)	These are variable costs other than fuel costs and include other consumables. This is relevant primarily for fossil fuel plant
Fixed Operation and Maintenance (Fix O&M)	These are the non-avoidable cost and overheads incurred in the operation of the plant such as staffing costs and unplanned and planned maintenance.
Run-up Rate (MW/min)	The rate at which a generator can reach minimum operating generation level after it is turned on.
Ramp Up (MW/min)	The maximum rate at which a generator can increase its output when running at normal conditions between minimum load and maximum load
Ramp Down (MW/min)	The maximum rate at which a generator can decrease its output when running at normal conditions between minimum load and maximum load
Minimum Down Time (hours)	The minimum amount of time a generator must be off-line after it has shut down before it can be restarted
Minimum Up Time (hours)	The minimum amount of time a generator must remain on-line and generating before it can be turned off, after it has been started
Forced outage rate (%)	The amount of time per year that the generator is expected to be unavailable due to unplanned or forced outages
Planned outage rate (%)	The percentage of time each year that the generator is unavailable due to planned maintenance and repairs
Minimum Generation	the percentage of the maximum power level at which the plant must be maintained for stable operation

These parameters take on the following values for the different generation types below:

Table 20 Operating parameter of generation plant

Technology	CCGT	OCGT (Large)	OCGT (Small)	Diesel	New Coal	Old Coal	Geothermal	Hydro	Wind	Solar
Heat rate GJ/MWh	8.9	13.9	17.3	11	10.9	10.9	N/A	N/A	N/A	N/A
Variable O&M ($/MWh)	0	15	15	0	0	0	0	0	0	0
Fixed O&M ($/kW/year)	20	10	10	8	45	45	48	38	60	26
Start Cost ($)	2000	2000	2000	N/A	2000	2000	N/A	N/A	N/A	N/A
Run up time (hrs)	2	0	2	0	3	4	N/A	0	N/A	N/A
Ramp Rate Up (MW/min)	10	20	20	50	2	2	N/A	0	N/A	N/A
Ramp Rate Down (MW/min)	10	20	20	50	2	2	N/A	0	N/A	N/A
Minimum Down Time (hrs)	48	1	1	1	48	48	48	48	N/A	N/A
Minimum Up Time (hrs)	24	1	1	1	24	24	24	24	N/A	N/A
Forced Outage rate	10%	10%	10%	10%	10%	15%	10%	10%	5%	5%
Planned Outrage rate	10%	10%	10%	10%	10%	20%	10%	10%	5%	5%
Mean Time to Repair (hrs)	24	24	24	24	24	24	24	24	24	24
Minimum Generation	40%	20%	50%	0%	40%	60%	N/A	0%	N/A	N/A

Fuel Costs

The key drivers of the operation of the existing thermal fleet and its cost of operation are the fossil fuel costs. For Indonesia this is primarily (lower calorific value) black coal, natural gas (often delivered in liquefied form or LNG), and diesel.

To estimate the fuel prices in $/GJ, each relevant input assumption was included. To calculate the following costs for each fuel, we use price assumptions as stated in the following tables.

Table 21 Coal prices

Attribute	Value	Source
kg/ton	907	-
kcal/kg	4200	-
kcal/kj	4.184	-
USD/ton	$50	IESR estimate
Coal (USD/GJ)	**$3.14**	

Table 22 Gas prices

Attribute	Value	Source
$/mmbtu	$7	Pp V-28 Table 5.40 Assumption of Fuel Price RUPTL
Kcal/mscf	252,000	-
kcal/kj	4.184	-
Mmbtu to mscf	0.9756	-
Gas (USD/GJ)	**$6.81**	

Table 23 Diesel prices

Attribute	Value	Source
USD/litre	$0.46	Based upon Brent Crude @ US$54/barrel as at May 2018
kcal/l	9070	-
kcal/kj	4.184	-
Diesel (USD/GJ)	**$12.21**	

Table 24 Summary of fuel prices and CO² emissions summary

Fuel	Price	Units	Production Rate	Units	Source
Coal	$3.14	USD/GJ	90.32	Kg CO2eq /GJ	AEMO NTNDP 2017
Diesel	$12.21	USD/GJ	70.2	Kg CO2eq /GJ	ibid
Gas	$6.81	USD/GJ	51.53	kg CO2eq /GJ	ibid

Modelling Methodology

To examine the impact of adding renewable generation to the existing portfolio of mainly large-scale thermal and hydro generation in Java, Bali and Sumatra we examined a number of factors to assess the validity of these proposals. The PLEXOS model is utilised as it optimises the solution at minimum economic cost or other applied criteria, such as meeting a minimum level of renewables etc.

Scenarios Overview

To assess the impacts of various key system investment drivers over the RUPTL horizon of 2018-2027 we have created a number of alternative scenarios. The high-level objectives of the study as encoded in the scenarios were to:

a. identify the impact of reduced demand

b. assess the impacts (cost and reliability) when wind and solar come in at considerable shares.

Drivers

There are two categories of drivers that determine the outcomes of the model:

1. Policy and investor decisions: Includes factors in the direct control of government and investors. Covers factors such as targets and PLN and IPP plans regarding specific outcomes and timing of investments. For example, PLN's investment plan and renewable energy percentages or nationally determined contributions (NDC's).
2. External factors and global trends: Includes factors out of the control of government or investors. Covers domestic and global technological and economic trends that impact drivers such as electricity demand growth or cost of capital.

Demand

Scenario	Demand	Investment
RUPTL	High	Fixed
RUPTL_ Low gen	Moderate	Fixed
RUPTL_ Low cap	Moderate	Optimised

Renewable Energy Share

Scenario	New Capacity Build	Capex and WACC
RUPTL_ Low cap	According to RUPTL	Standard
RE_Medium	Fossil Fuel + Renewables	Standard
RE_High	Renewables*	Standard
Energy Transition	Renewables*	Low

*with OCGT for system reliability

Figure 18 Scenario overview

Table 25 Description of Scenario

Scenario	New Build conditions	2027 Renewable Target	RES CAPEX	Renewables WACC
RUPTL	This scenario corresponds directly to PLN's 2018 RUPTL which set out the proposed generation and transmission investment plans from 2018-2027. We replicate and cost out the capex and operational costs of the entire fleet for Java-Bali and Sumatra systems including our best estimates of the following key factors: • Construction costs • Timing of transmission interconnection and expansion	None	Medium	Medium
RUPTL_low gen (Moderate demand)	As in the RUPTL scenario but demand is lower based on our analysis of annual growth rate of 4.6% for Java-Bali and Sumatra for the period 2018-2027 in contrast with the RUPTL forecast of 6.6% growth. This impacts only power plant utilisation and through its reduced variable operation costs.	None	Medium	Medium
RUPTL_low-cap (Optimised investment)	As RUPTL_low with reduced demand growth but with all planned and committed RUPTL plant considered by the Plexos LT Plan optimiser as potential candidates but not all generators are required to be built. Timing of investment is also determined by Plexos. Only renewables that are in the RUPTL are considered including limited amounts of wind and solar PV. This scenario tests the need for all the plant that is planned in RUPTL and in particular tests impact of reduced demand forecasts on coal build-out.	None	Medium	Medium
RE_Medium	As in RUPTL_low-cap but generic new build wind and solar is available. This scenario includes a moderate renewable energy target of 30% by 2027 to emulate increased government appetite for renewables. Expansion of Indonesia's existing renewables fleet of geothermal and hydro-electric is deployed as per the RUPTL.	30% by 2027	Medium	Medium
RE_High	This is a strong energy transition scenario where we model a situation where the government has chosen to go after a Paris-compliant future where all new investment is covered only by Wind and Solar as well as RUPTL candidate renewables including Hydro and geothermal. Generic OGCT is also available for meeting reliability requirements as a cheap way of balancing the variability of solar and wind.	43% by 2027	Medium	Medium
Energy Transition	This is the true energy transition scenario, where an accelerated technology and policy-driven investment transition is taking place. This leads to lower capital costs and lower WACC due to reduced perception of risk of investment in solar and wind.	As in High RE	Low Solar Wind	Low

Sensitivities

Some of the outcomes of this modelling exercise can be quite sensitive to key parameters including weighted average cost of capital (WACC) assumptions and fossil fuel costs. We therefore performed sensitivity analysis to 3 scenarios related to Renewable Energy Share, namely RUPTL Low cap, RE Medium and RE High.

Results and Discussions

This section sets out the results of the modelling which are divided into two main topics:

- Impact of moderate demand growth
- Impact of higher shares of wind and solar

Impact of More Moderate Electricity Demand growth

In this first part of the analysis we compare three scenarios looking at the impact of a more moderate demand growth. As a baseline, we use demand and generation capacity data for 2027 from RUPTL 2018. For comparison, we model two alternative scenarios with more moderate demand growth of, on average, 4.6%. Peak load would increase from 34.4 GW to 40.6 GW rather than to 59.1 GW as in RUPTL. In “RUPTL_Low gen”, we do not change the generation park of the RUPTL, but rather only look at the impact of lower demand on the generation, and, consequently operational cost. In “RUPTL_Low cap”, we optimize the power plant portfolio, i.e. from the generation park in the RUPTL, only those generators are built that would be needed to meet moderate demand.

Generation capacity

When we further examine the alternate 2027 scenarios in Figure 19, the initial observation is that the RUPTL_low cap scenario, which is where the model only builds what is economically efficient to meet the demand, shows a reduction in generation capacity of approximately 12.5 GW, mainly of coal (-3 GW), CCGT and OCGT (-6GW) and diesel (-1.6GW).

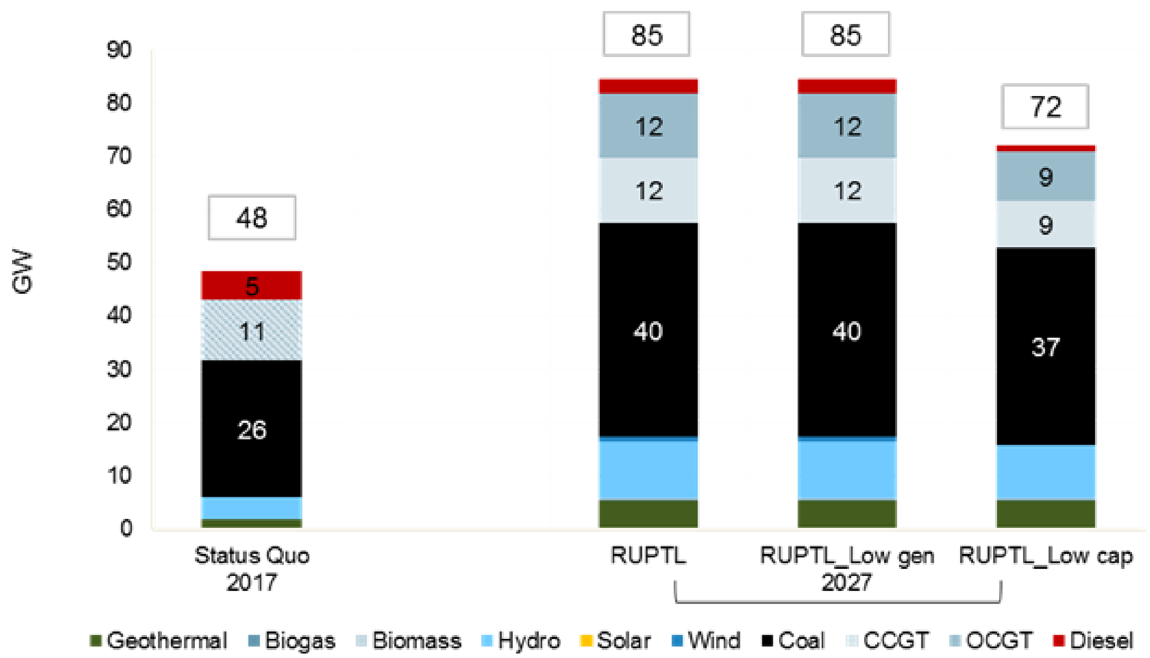


Figure 19 Installed capacity in 2027 between RUPTL and the optimised system

Energy Generation

In terms of generation,

- geothermal and hydro mostly unchanged, as low/zero short run marginal cost; impact on coal, OCGT and CCGT – reduction by 31 TWh, 16 TWh and 13 TWh respectively (12%, 56% and 28% reduction)
- compared to today, gas share lower, geothermal and hydro, but also coal shares increase

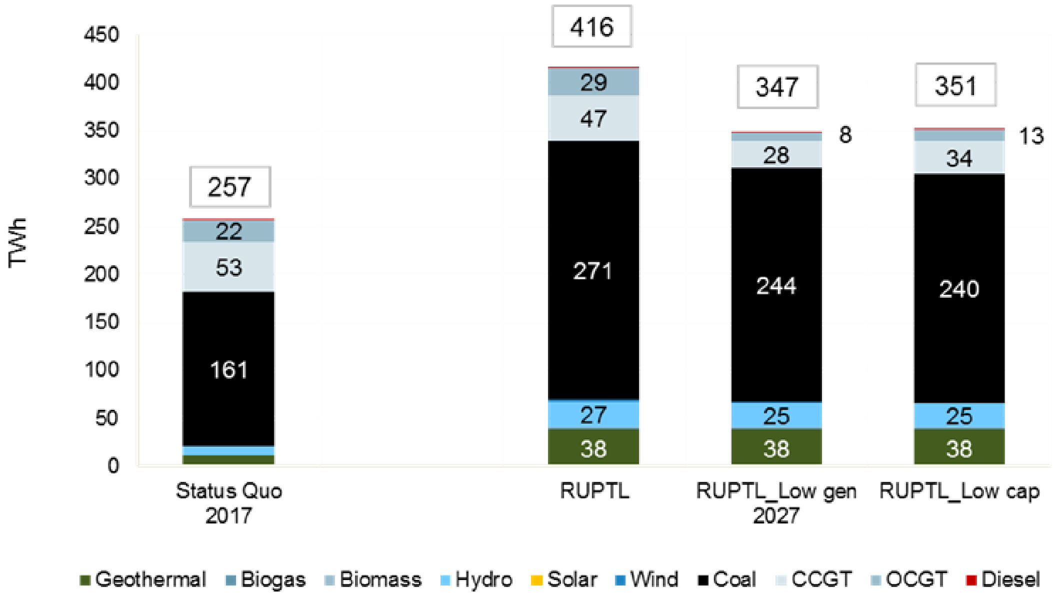


Figure 20 Generation mix in 2027 between RUPTL and the optimised system

Utilisation

Comparing RUPTL low with RUPTL low opt., utilisation of thermal power plants is lower in the moderate demand case, since a higher number of power plants produces the same amount of energy. The decrease in utilisation rate for coal, CCGT, OCGT is as follows:

Table 26 Utilisation Rate of Each Technology

	RUPTL	RUPTL_Low gen	RUPTL_Low cap
Biogas	77.4%	74.9%	79.3%
Biomass	80.0%	80.0%	80.0%
CCGT	**44.0%**	**26.2%**	**42.7%**
Coal	**76.8%**	**69.2%**	**74.9%**
Diesel	2.9%	0.1%	0.2%
Geothermal	80.0%	80.0%	80.0%
Hydro	28.5%	27.0%	28.9%
OCGT	**27.4%**	**7.7%**	**16.6%**
Solar	12.2%	12.2%	13.5%
Wind	23.1%	23.1%	26.5%

This value may seem not that large at first sight; the impact of lower demand does become more pronounced, however, when looking at the utilisation on a power plant basis. It becomes evident that the utilisation rate of certain coal and gas-fired power plants may actually be reduced by a considerably higher value. There are more than 20 power plants whose utilisation rate is going down by more than 10 percentage points, and six power plants whose utilisation is reduced by around or even above 20 percentage points. The reduction in utilisation is visualised for all plant in the figure below.

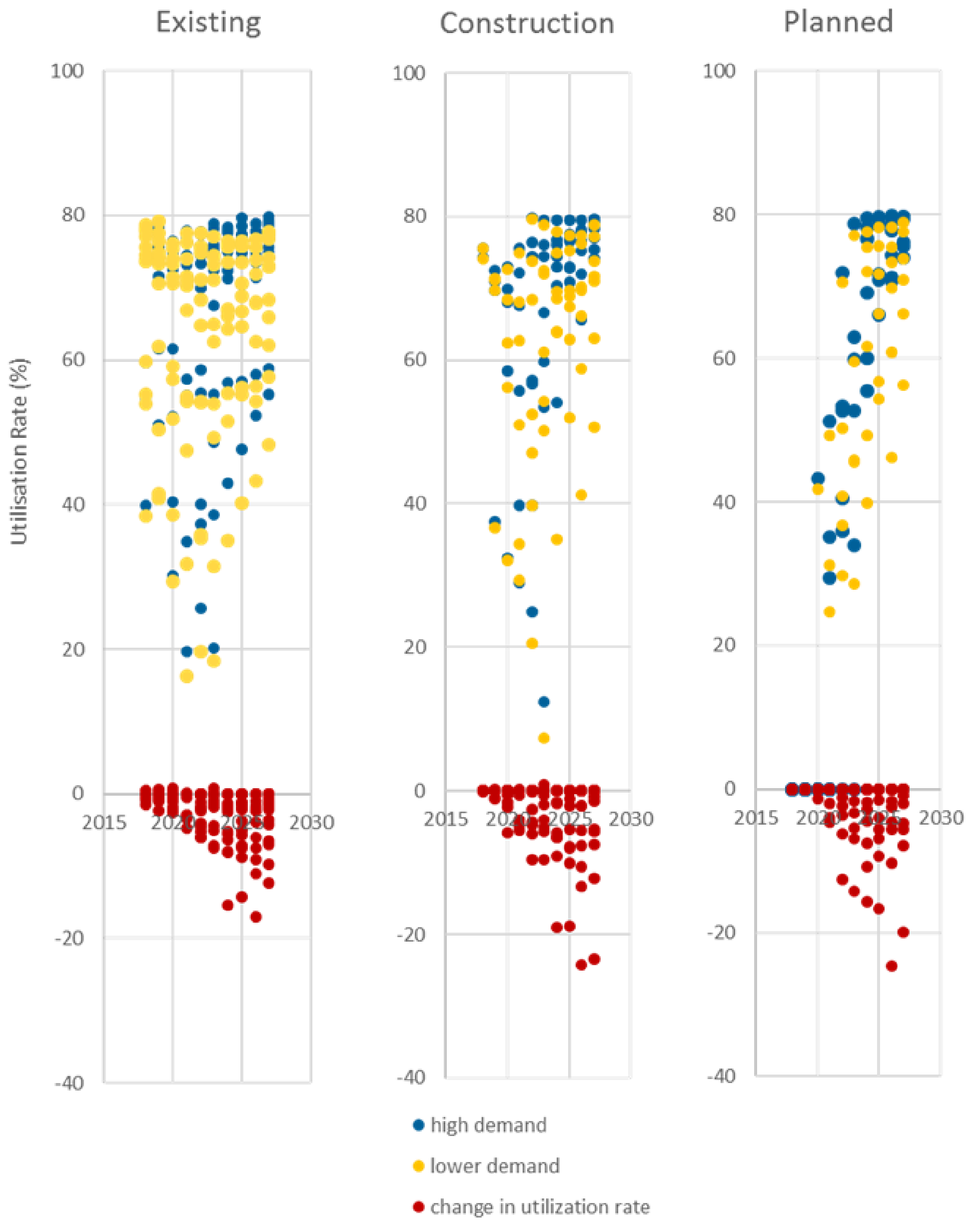


Figure 21 Changes in utilisation rate between high demand and lower demand scenario (depicted by the red points). Each point represents 1 coal power plant in 1 province. The power plants are grouped into 3 status: existing, under construction, and planned.

While the modelling, as it assumes similar efficiency parameters for most, may not be able to precisely take into account individual efficiencies and operational cost, it is still highly probable that also in real world terms, a considerable number of coal and gas-fired power plants would be utilised to a much lesser extent than planned. This may even be true for new plants, putting their business case at risk.

System cost

In a system cost comparison, the cost on the supply side of the three scenarios are assessed. Since the transmission system is a constant input assumption, and not part of the optimisation, transmission costs are not taken into account here. According to the current planning of PLN in the RUPTL, the supply sides focuses on thermal generation capacity. Consequently, system costs are largely driven by operation cost, which account for about 60% in the RUPTL scenario. In the “RUPTL_Low gen” scenario, generation capacity and therefore associated capital cost remain unchanged; there are savings on the OPEX side, due to reduced fuel cost. OPEX is down from US$91 billion to US$77.4 billion as compared to RUPTL, overall cost is reduced by 12%.

Assuming that the only capacity that is built is that needed to cover peak demand (depicted by scenario RUPTL_Low cap), then the reduction in demand would result in a decrease of CAPEX by US$ 1.7 Billion; OPEX would remain largely unchanged. Overall, compared with the “RUPTL_Low gen” scenario, the system cost of RUPTL_Low cap would be down by US$ 3.6 Billion, or 3%.

From Figure 21 we can see this results in the RUPTL scenario’s system being 13% more expensive than needed of which 3% of the unnecessary cost is due to annualised value of new build generation capital. This overbuild cost is related to 12.5 GW of capacity that is not required to meet demand, as shown in Figure 18. Building these extra 12.5 GW of plants would require unnecessary investment of about US$12.7 billion; total investment cost would increase from US$39.7 billion to US$52.4 billion. This would, by the year 2027, increase annual capital cost of the power plant park by 28%.

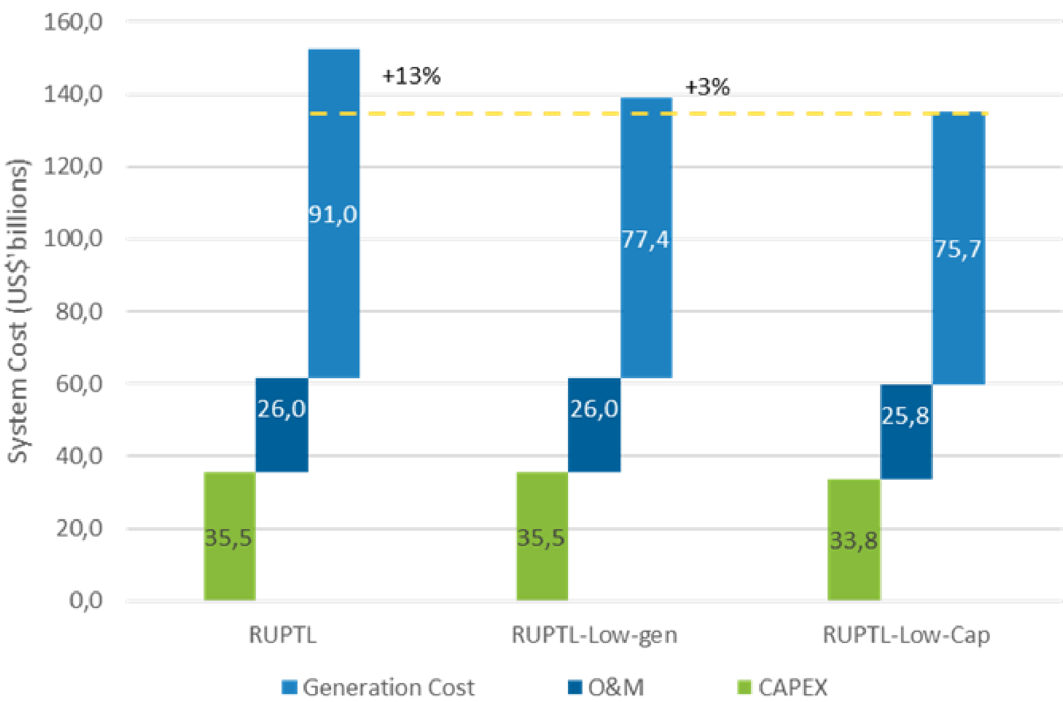


Figure 22 Total 2018-2027 system cost comparison between RUPTL and optimised system under RUPTL boundary

Impact of higher shares of Wind and Solar on Java-Bali-Sumatra power system

In this second part of the analysis, we look at the impact of adding higher shares of wind and solar power in the generation mix of Java-Bali and Sumatra. As a reference scenario, we use the RUPTL_Low cap, i.e. the scenario discussed previously, which assumes moderate demand growth, and an adopted power plant technology mix, which reflects the technological preferences expressed in the RUPTL. We compare this baseline with two scenarios that are based on the same demand assumptions but assume higher shares of wind and solar. While in the reference case, renewables – mainly hydro and geothermal – make up nearly 19% of annual generation in 2027, in the alternative scenarios, the renewable share is set to increase. Generally speaking, the High RE scenario would imply that all new generation capacity between 2018 and 2027 would come from renewables – solar, wind, hydro, and geothermal. In the Medium RE scenario, about half of additional generation would come from renewables, the other half from coal and gas.

Generation capacity

The reference case installed capacity and the RE Medium and RE High capacities modelled were:

- Reference case: results in mix of around 37 GW coal, 18 GW combined CCGT and OCGT, 10GW hydro, and 5GW of geothermal
- Medium RE: 19 GW of Solar PV and 8 GW of wind, coal down by 5 GW to a total of 32GW, CCGT and OCGT down by 3 GW to a total of 15 GW.
- High RE: Solar capacity is higher than Medium RE by 16 GW, rising to 35 GW. Solar thus has the largest capacity share of all the technologies, wind more than doubling to 19 GW; coal down by 31% compare to the Medium RE to 22 GW, CCGT almost unchanged, OCGT up 50% to 12 GW – needed for balancing. This provides better cost structure when it comes to lower utilisation rates of remaining coal.

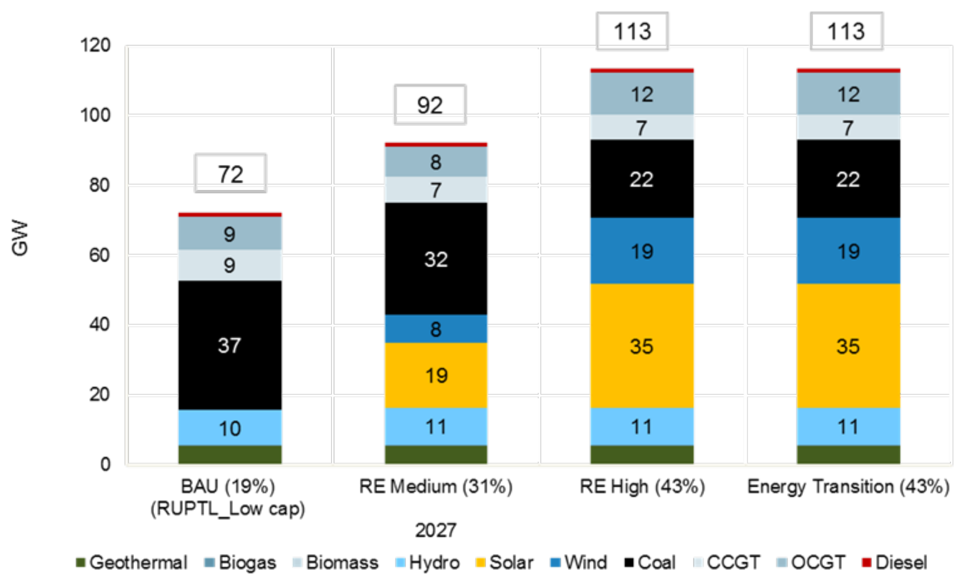


Figure 23: Generation Capacity in 2027 for Renewables

Generation Mix

Differences in the above capacity mix are also reflected in generation mix; due to the different capacity factors the generation mix is, of course, quite different. Here the renewable energy shares are:

- RUPTL_low cap: 18.6%
- Medium RE: 31.0%
- High RE: 43.4%

In the Medium scenario Figure 24 shows geothermal and hydro (almost unchanged) at 27 and 38 TWh, then solar and wind grow to 23 TWh and 18TWh. Coal generation goes down 14% from 240 to 206 TWh, CCGT is down by 14 %, OCGT nearly halved due to reduced utilisation rate. In High RE scenario, coal further reduced to 141 TWh, down 41% from reference case; solar and wind surpass geothermal and hydro, but overall balanced mix of these four renewables sources, all between 27 and 43 TWh each combine to a 43% RE share.

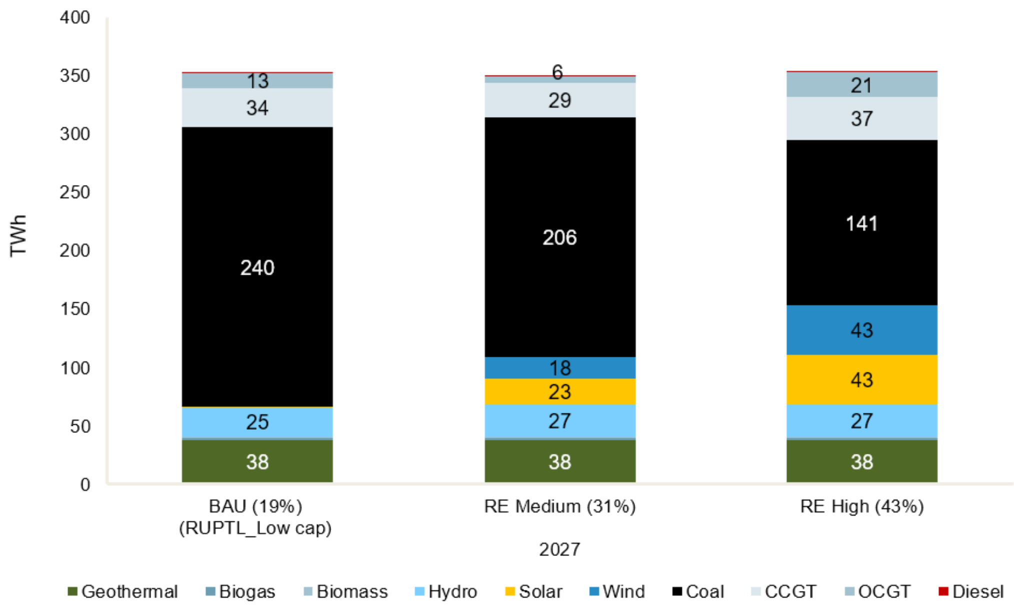


Figure 24: Energy Generation Mix in 2027 by Technology for RE Scenarios

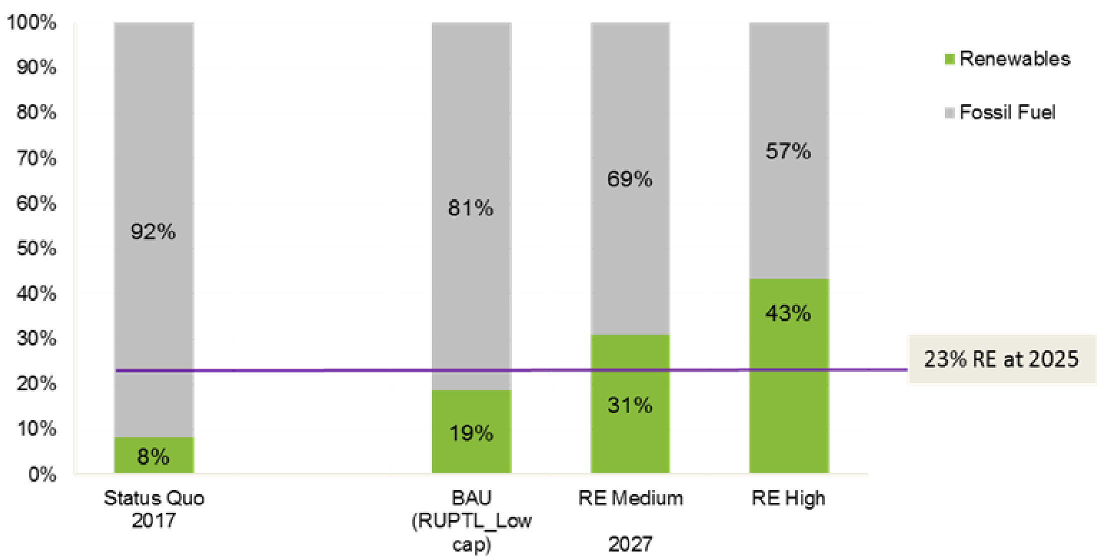


Figure 25 Renewable energy mix by 2027 for BAU and RE Scenarios

Utilisation

Comparing the RE scenario with RUPTL_Low cap, we see that because no new coal or CCGT capacity is available the utilisation of existing CCGT increases along with increased utilisation of OCGT.

Table 27 Generator utilisation rates by technology in 2027 for RE scenarios

Technology	RUPTL_Low cap	RE Medium	RE High
Biogas	79.3%	79.8%	79.7%
Biomass	80.0%	79.9%	79.7%
CCGT	42.7%	42.5%	56.1%
Coal	74.9%	73.9%	72.5%
Diesel	0.2%	0.1%	0.2%
Geothermal	80.0%	80.0%	79.9%
Hydro	28.9%	28.6%	28.8%
OCGT	16.6%	12.5%	19.4%
Solar	13.5%	14.0%	13.7%

System Costs

The financial impacts of the transition to a larger penetration of renewables in the Java-Bali-Sumatra system are investigated by reporting the total operating and annualised investment costs for the period 2018-2027. These are shown in Figure 26 which shows the total cost for the four scenarios – RUPTL_Low cap as baseline, Medium and High Renewables and Energy Transition scenarios.

We see that using a consistent set of assumptions the simulations show that the RUPTL_low-cap reference case comes at lowest overall cost of US$135.4 billion over the ten-year period. Medium RE scenario is 4% higher; and High RE 7% higher; in the Energy Transition scenario, with lower WACC at 8% and a steeper learning curve for solar and wind, system cost goes down to $134.2 billion, lower than in the RUPTL reference case.

The higher the share of RE, the higher the CAPEX, due to the cost structure of RE, which is highly driven by CAPEX (in general, capex makes up more than 90% of the cost of RE technologies). For High RE scenario, CAPEX share is 36% of the total system cost. In comparison, in RUPTL_Low cap, with less than 20% Renewables, CAPEX share is only at 25%, as here, system costs are dominated by operating cost, mainly fuel. However, as we will see in the next chapter, the impacts of various changes in assumptions such as WACC or fuel cost can swamp these differences. In essence the results show that a highly renewable system for Indonesia's main islands is not only realistic today but also affordable.

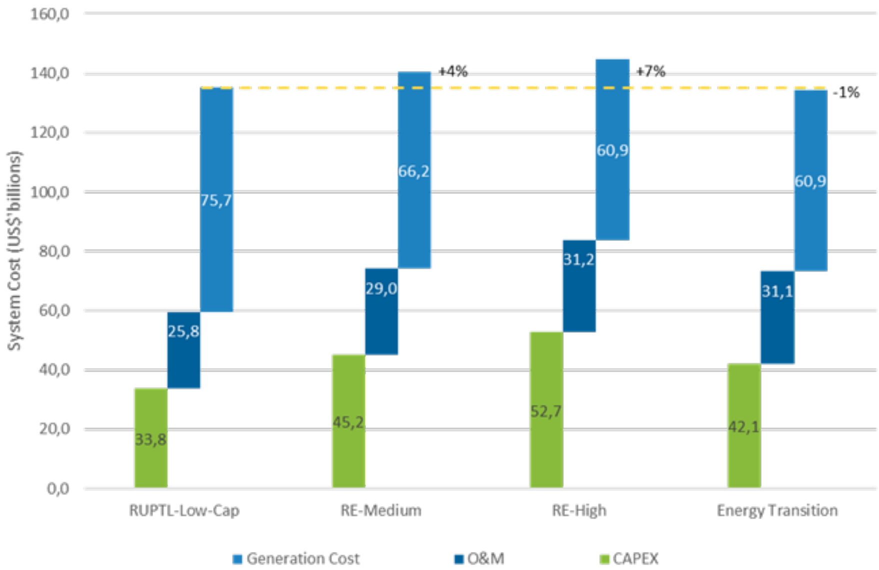


Figure 26 Total operating and investment cost for Java-Bali-Sumatra 2018-2027

Cost of Capital Sensitivities

The impacts of increased cost of capital for funding solar and wind projects is explored and the results are shown in the figure below.

We find that a significantly increased view of investment risks in solar and wind (15% WACC instead of the default 10%) has considerable impacts on that total cost of the system which by 2027 has more than 56 GW of solar and wind combined.

The cost difference between RUPTL_Low cap, with almost zero wind and solar, and the High RE scenario, increases from 7% to 16% at 15% WACC. However, if the investment risks in solar and wind becomes more conducive than for fossil fuel generation, the High RE scenario is already on par with the RUPTL Low cap. This happens at WACC of 7.5%. If the WACC

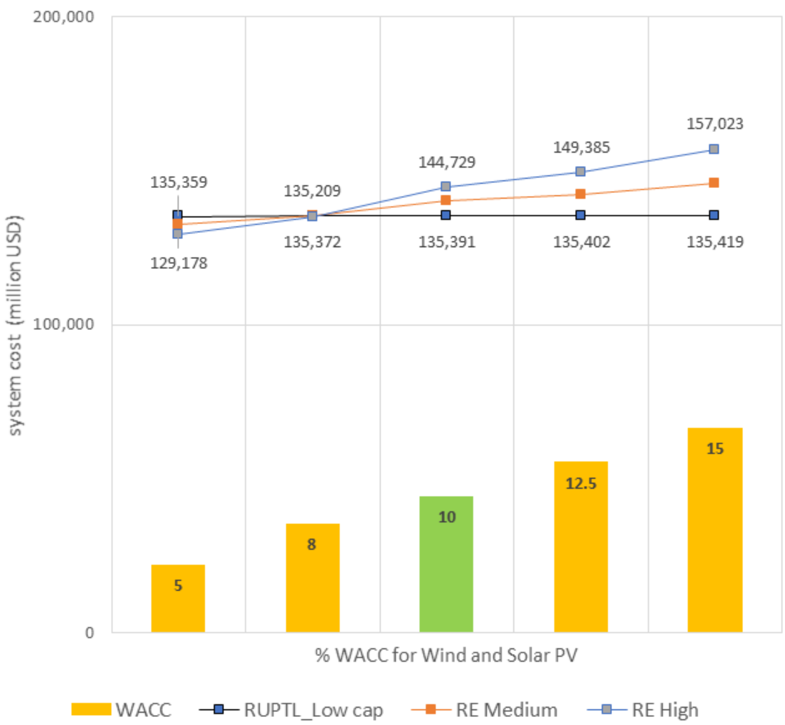


Figure 27 System cost impacts of changes in weighted average cost of capital

would go further down to 5%, which is the case in a lot of countries with high development of renewables, the system cost of High RE scenario will be cheaper by 4.5% than the high fossil fuel scenario.

Fuel Price Sensitivities

In our base case we assume fossil fuel prices of coal \$3.14/GJ, and gas \$6.81/GJ. The coal price assumed, which refers to coal quality of 4200 kcal/t, corresponds to a world market price, set for higher value coal (value of 6300 kcal/t) of \$ 90/t coal. We performed coal price sensitives on the scenarios to analyse the changes in system cost respective to coal price changes. We applied an upper limit price of US\$ 80/ton price for coal – which would represent the highest record level for the relevant coal type and quality. The results are shown in Figure 28 that shows impacts of higher coal prices on the RUPTL_low cap scenario, and the impact of these higher fuel prices on overall system cost comparison with the medium and high RE scenarios.

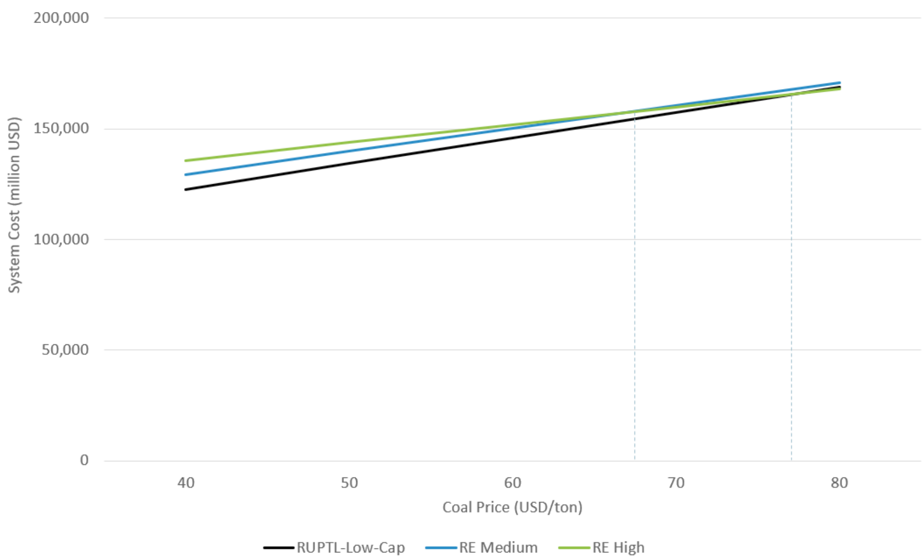


Figure 28 System cost sensitivities to higher coal prices. Percentage relative to base (black line)

The results are intuitive. The scenarios with the highest coal penetration experience the highest cost increases. This leads to a final conclusion that in a higher coal case which is more reflective of recent trends, the highest renewable penetration scenarios such as RE High are shielded from price volatility. In a situation such as US\$ 70 - 80/ton, the High RE scenario is cheaper than the RUPTL.

Transmission

This section reports the outputs of the simulation results for transmission flows. We report the loading of the lines in either direction of transport. These show that there is a dominant direction of energy flows in many scenarios.

Inter-regional Transmission Java – Sumatra Interconnection

This interconnection has been under consideration for some time but has not yet materialised. In general interconnection between major load and generation regions is considered to be a good way to reduce cost and increase system reliability. Based on advice from IESR's network of stakeholders we anticipated that a realistic date for completion of this interconnection is 2023.

In the RUPTL case, business case for interconnection is (coal) fired power to be sent from Sumatra to Java – 18 TWh/annum of power flowing, with almost none in the other direction; in the RUPTL_ Low cap this reduces to 6 TWh/annum and in the Medium RE scenario this flow is reduced ever further to 2TWh/annum with a more bidirectional usage of the interconnection with a loading rate of only 8.4% from Sumatra to Java. Then in the High RE, somewhat higher flows return at around 5TWh/annum and a loading rate of nearly 18% reflecting that wind / solar power appears to be exported to Java. It can be concluded that the richness of solar resources in Sumatra supports a business case for interconnection. However, given the relatively low loading rates and almost no congestion shown in the model in any except the RUPTL scenario, it may be that the connection can be substantially smaller in a RE future.

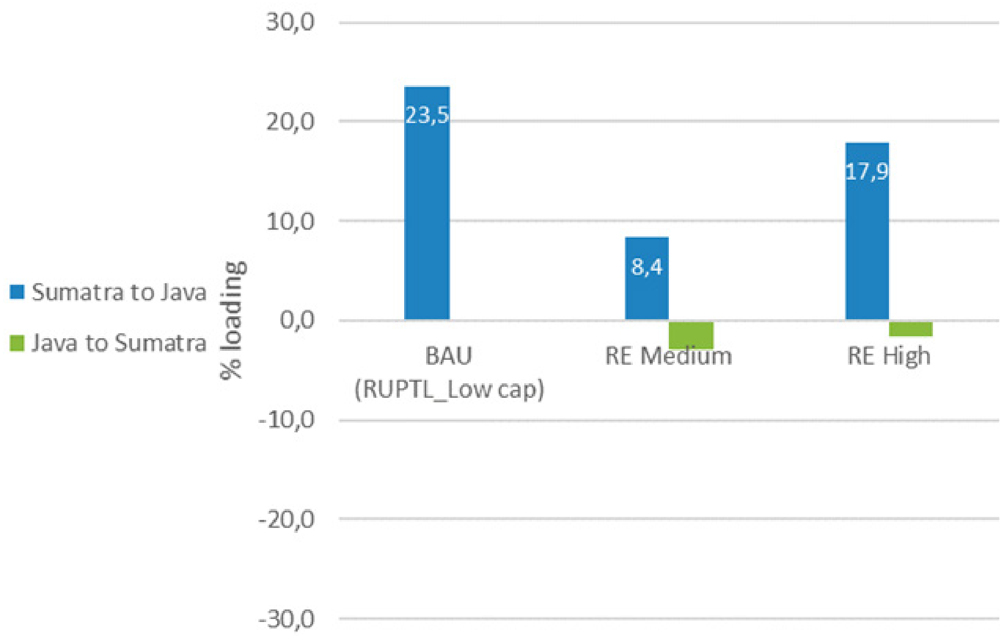


Figure 29 Utilisation of Java-Sumatra Interconnection in 2027

Inter-regional Transmission Java – Bali Interconnection

With the growth in demand in Bali outstripping expected generation investment, and with limited development potential for conventional generation, there is a current business case for expansion of the Java-Bali interconnection.

In the RUPTL case, business case for IC is (coal) fired power to be sent from Java to Bali – 5.7 TWh/annum, with none in the other direction; in the RUPTL_Low cap this reduces slightly to 4.6 TWh/annum showing there is still a significant deficit in Bali with 26% utilisation shown in Figure 30. In the Medium RE scenario this flow is reduced to 2.7 TWh/annum with small flows in the opposite direction and a loading of only 15% from Java to Bali. Then in the High RE flows continue to decline to 1.5 TWh/annum and a loading rate of 9% reflecting that sufficient wind and solar power has been deployed in Bali. Given the cultural sensitivities around use of land in Bali, this needs to be address in more detail in subsequent studies.

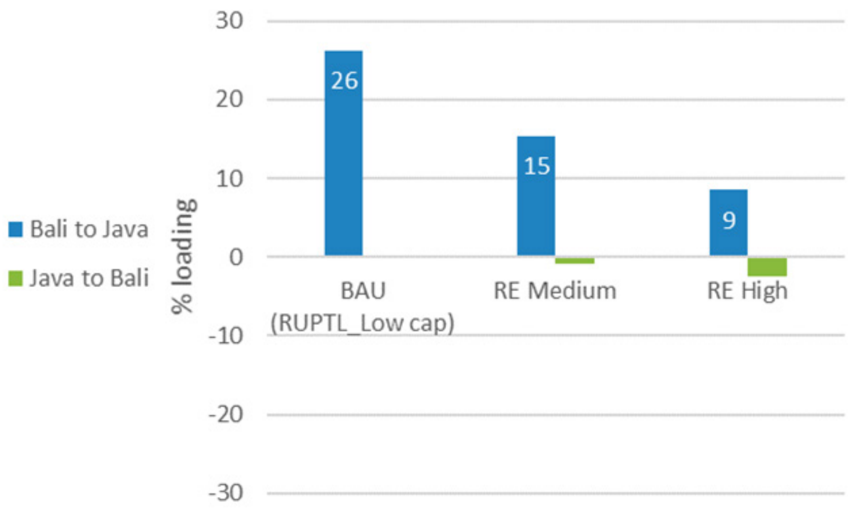


Figure 30 Utilisation of Java-Bali expanded interconnection in 2027

System Emissions

The total CO2 emissions of the combined Java-Bali-Sumatra system are shown here just for the year 2027. The difference in emissions is significant between the reference RUPTL_low-opt scenario and the Medium and High RE scenarios: As shown in Figure 32 emissions are down by 16% / 36% in the RE Medium and RE High scenarios.

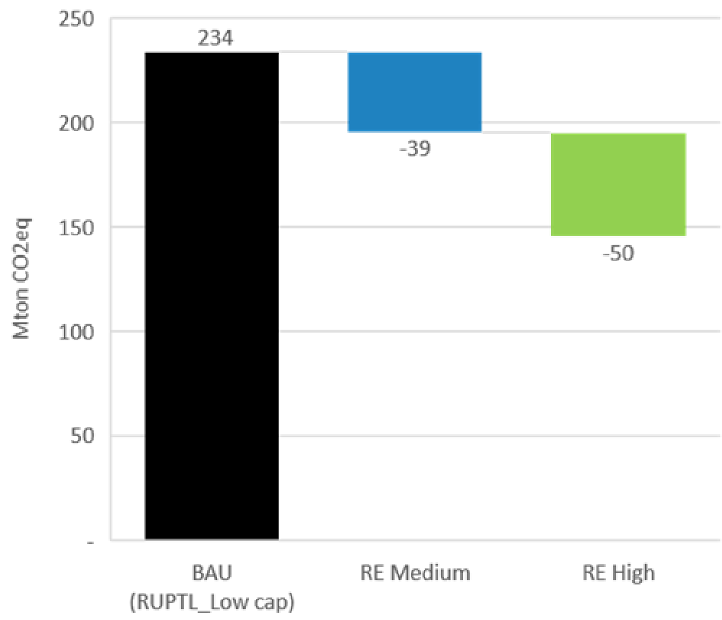


Figure 31 Total CO2eq emission in 2027. Medium 16% lower than BAU, and RE High scenario is 36% lower compare to BAU

The emission reduction pathway can be seen in more detail in Figure 31 that shows the significant progressive decline in emissions intensity. The small gradual rises that can be seen at times occur during periods where demand growth driving higher fossil plant utilisation outstrips impacts of renewable generation investment.

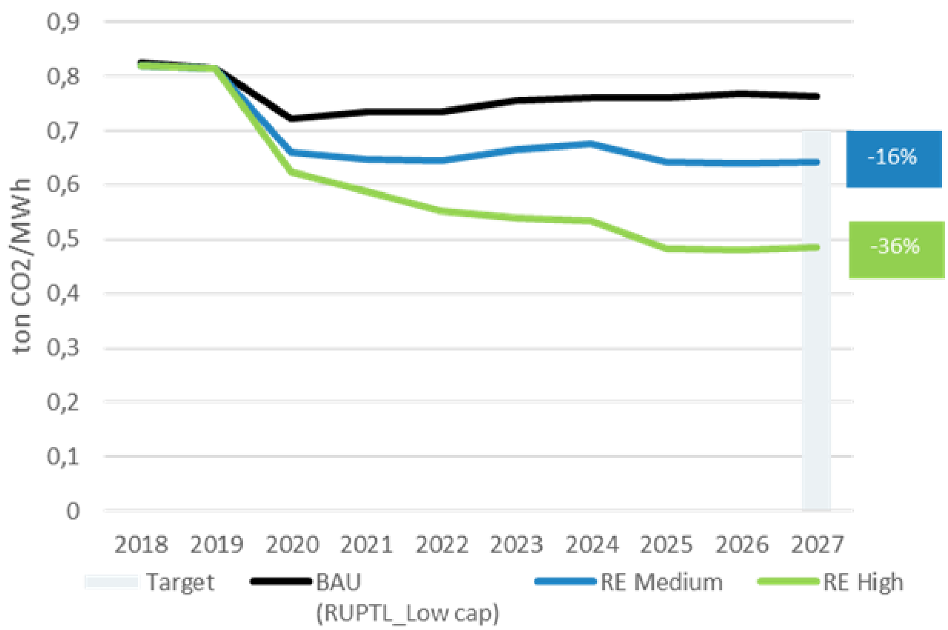


Figure 32 CO2eq Emission Intensity of Power Sector; Target: 0.7 ton CO2eq/ton (RUPTL, 2018)

System Reliability

One of the key criticisms put forward by the opponents of wind and solar technologies is that their variability would lead to lack of system reliability. We therefore carefully studied the reliability implications for the different scenarios.

System reliability is measured by percentage of unserved energy. The Indonesia reliability standard is set at 1 day of unserved energy per year or expressed as a percentage: 0.274%.

Table 28 System reliability as measured by percentage of unserved energy.

Year	RUPTL	RUPTL_Low gen	BAU (RUPTL_Low cap)	RE Medium	RE High
2018	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2019	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2020	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2021	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2022	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2023	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2024	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2025	0.0000%	0.0000%	0.0000%	0.0000%	**0.0003%**
2026	0.0000%	0.0000%	0.0000%	0.0000%	**0.0012%**
2027	**0.0050%**	0.0000%	0.0000%	**0.0002%**	**0.0044%**

The table above clearly shows that the impacts on reliability are negligible. In fact, the reported reliability is much better than the 0.274% unserved energy standard. This is somewhat unrealistic clearly as even the RUPTL scenario shows reliabilities well below those currently experienced. What is important however is the relative difference in reliability between a fossil generation-based buildout and the high renewables scenarios. A more detailed study would require more precise modelling of component reliabilities including transmission forced outages and more precise numbers on the availabilities and reliabilities of existing fossil generators.

Flexibility of operation of thermal plant

To understand the sensitivity of the system to a large amount of renewable generation, it is useful to investigate the operation of all plant and particularly coal and CCGT plant at an hourly resolution to determine whether the behaviour shown is consistent with realistic thermal plant flexibility. Despite the preference of coal and combined cycle natural gas plant (CCGT) to operate as base-load, as that is where economies of scale make it cost effective, collectively the coal and CCGT fleet is able to provide a large amount of flexibility. In order to assess the ability of the coal and CCGT plant to support renewables variability it is useful to plot the hourly generation of the system's different technology types as shown below.

Hourly generation

In this section we show the hourly generation for the combined Java-Bali and Sumatra systems for the first week of October of the year 2018 as compared to the same week in Scenario High RE 2027. This is the highest month for energy demand. Additionally, we also show the second week of October as an example of a case where solar and wind are less productive and hydro and other resources take over.

Hourly generation profiles in 2018

When we examine Java-Bali and Sumatra in 2018, much of the baseload is from geothermal and coal fired generation, and the coal-fired generation ramps down overnight in response to reduced system demand. Combined cycle generators also run 24-7 and show some flexibility as more intermediate plant, whilst most of the peak load is met by hydro generation and to a lesser extent OCGT's. Other technologies such as wind, solar and biomass make minimal contributions to the energy supply.

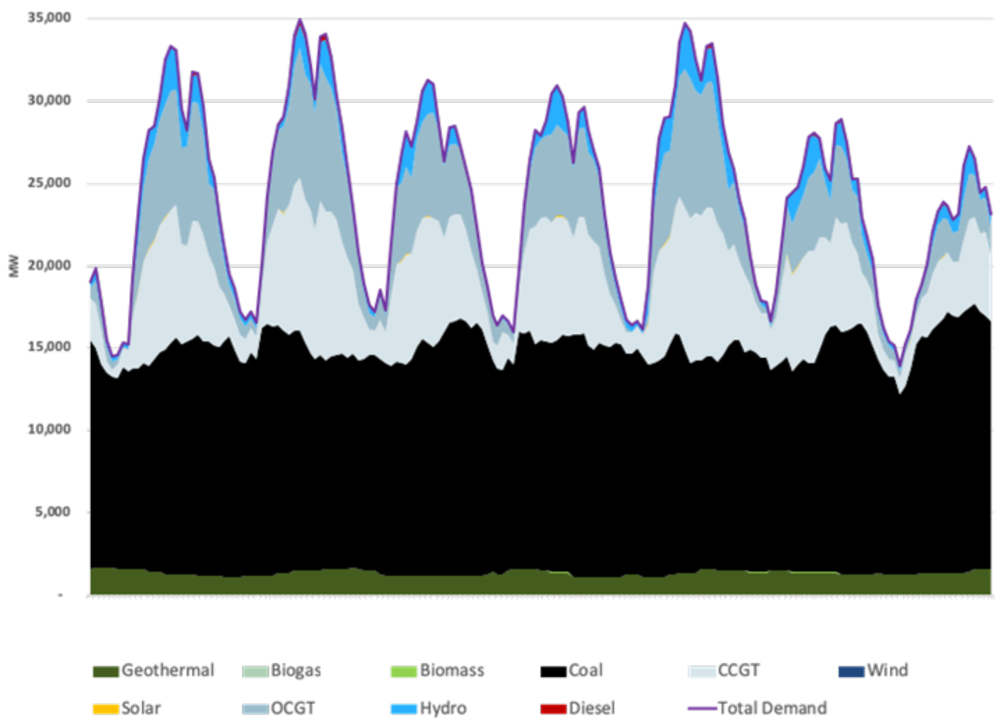


Figure 33 Hourly dispatch for a typical week in October 2018

Hourly generation profiles in 2027

When we examine the changes in Java-Bali in 2027, we can see that geothermal production still plays a baseload role and the production of coal-fired electricity is significantly reduced. Wind becomes a significant part of the mix, producing energy 24 hours a day. The impact of significant solar production is to change the behaviour of much of the hydro and OCGT generators, which is now pushed back until around 4pm each day.

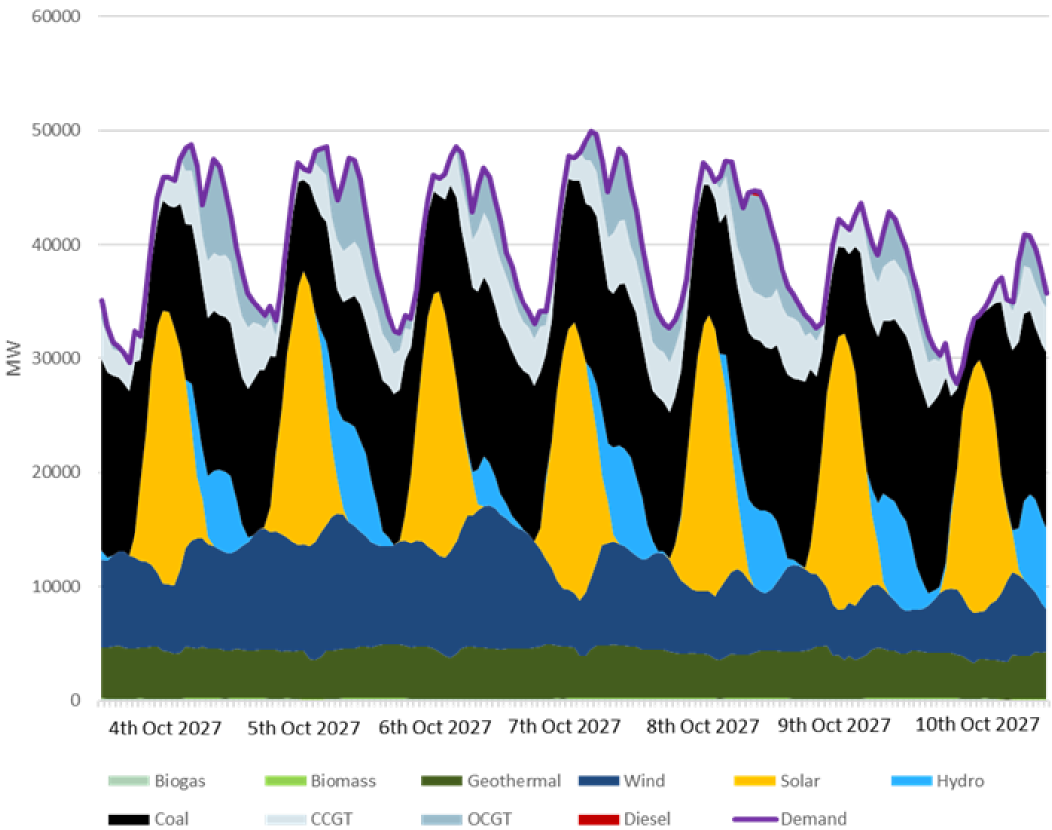


Figure 34 Hourly Generation Profile per Generation Technology (1st Week of October 2027)

Key findings

Assuming standard average technological capabilities for flexibility parameter of coal and CCGT plant such as minimum load and ramp rates, even in the High RE scenario system we modelled we find both a low level of unserved energy and sufficient thermal capacity to balance variability. At least in this case our study shows that it is feasible from an hourly perspective.

More specifically in Figure 34 and Figure 35 we see that:

- Solar has a distinct daily seasonality with solar peaking at around midday
- Wind varies more randomly but tends to be lower during the middle of the day. With the wind profiles we used, and the diversity of sites, wind generation almost never falls off to zero. This shows a level of complementarity between wind and solar
- Max upward ramping that coal was required to provide is about 4.3 GW / hour and downward ramping of - 6.2 GW/hour
- Balancing overall is provided by a mix of technologies, in particular OCGT and hydro; but given our conservative assumptions of coal operational parameters, coal is also able to change output as we saw above.

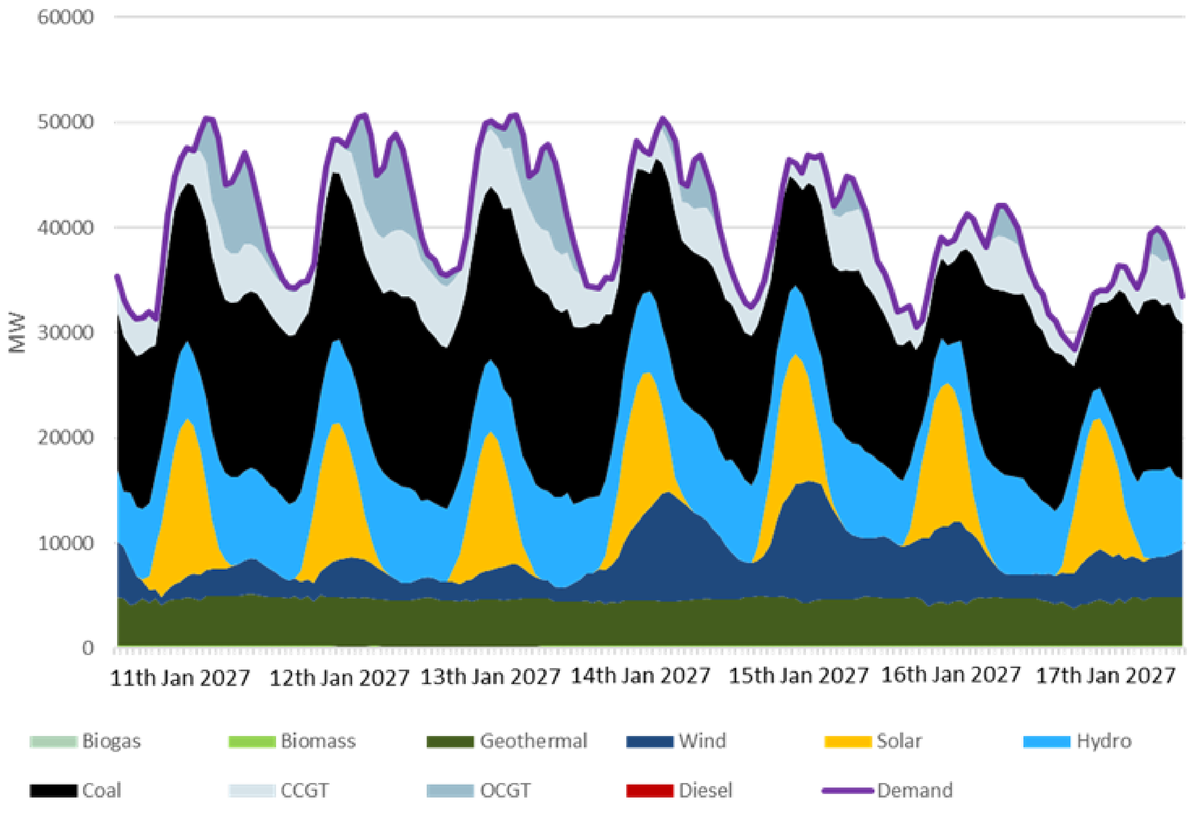


Figure 35 Hourly Generation Profile per Generation Technology (1st Week of January 2027)

Conclusion

This report describes the study that modelled different pathways for Indonesia's power system to reliably meet energy and climate targets for the period 2018 to 2027. The study focuses on Java-Bali and Sumatra where the majority of the population lives and about 90% of the electricity is consumed. The model assesses both the demand and supply dimensions of the power system.

The study has considered RUPTL 2018-2027 as the business as usual scenario and compared this against alternative scenarios where we have considered less aggressive demand growth projections and high levels of renewable penetration including a Medium Renewable Energy (RE) scenario which saw over 30% renewables by 2027 and a High RE scenario with 43%.

Analysis was performed with the Australian PLEXOS power system simulation and planning software system, which is widely used internationally for power sector analysis. The study identifies the impact of reduced demand on generation investment, utilisation and power system cost and assesses the impact of adding considerable shares of wind and solar capacity to the system.

When considering a more realistic set of demand scenarios and utilising PLEXOS to build power stations when required and in an efficient manner, we can observe that it is possible to build a significant amount of renewable generation. Importantly, we can see from the results that concerns about the difficulties and costs of integrating renewables are exaggerated. The scenarios are only marginally more expensive than a low demand business as usual and significantly cheaper than the current RUPTL plans, and could in some cases be even cheaper if coal prices increase or the energy transition accelerates providing cheaper technologies and investment capital.

These proposed alternative scenarios to the PLN's RUPTL show that the increase in renewables does not increase the level of unserved energy and that flexibility in the stock of existing plant, particularly OCGT and hydro, and to a lesser extent CCGT make up for the requirement to meet any need for sufficient ramp rate that the variability in renewable generation may cause.

Key findings:

- The Ministry of Energy and Mineral Resources and utility PLN have continuously overestimated energy demand in Java-Bali and Sumatra. If PLN continues with its current plans, there is likely to be an overbuild of 12.5GW of coal, gas and diesel, resulting in approximately US$12.7 billion in wasted investment. This would burden PLN's finances and eventually have to be covered by the Indonesian public.
- The risk of lower than planned utilisation of thermal power plants may increase as demand projections are overestimated and as renewables become cheaper. Once renewables are built, they produce electricity at almost zero marginal cost. This could result in additional losses for PLN, which is locked into long-term power purchase agreements with Independent Power Producers.
- Java-Bali and Sumatra could reliably meet growing electricity demand in the next 10 years through a doubling of the share of renewable energy. The cost of doubling the share of Renewables through investment in wind and Sslar is comparable to the current high fossil-fuel pathway. Greenhouse gas emissions would be reduced by 36%. The development of renewables would bring important additional co-benefits, reduce negative health and environmental impacts and provide job opportunities throughout the country.
- A high renewables scenario coupled with realistic energy savings would result in a cost saving of US$10 billion over ten years as compared with the current RUPTL plan if the cost of capital and cost of technology is brought down in line with international prices. This would require an ambitious long-term strategic plan, clear intermediate targets and implementing regulations in place.
- Even with a 43% share of wind and solar, the security of supply of the power system is maintained.

Recommendations

To develop a reliable, cost-effective energy system which avoids wasted capital and serious environmental impacts, MEMR and PLN should:

- Review best practice approaches and techniques in demand forecasting around the world and implement such an approach in Indonesia;
- Integrate the potential of energy efficiency for forecasting future electricity demand;
- Review current proposals for new coal-fired power stations in the Java-Bali and Sumatra systems and apply current prevailing costs for renewable technology in developing future plans to asses alternative cost-effective and low carbon pathways;
- Develop and assess alternative scenarios and low carbon electricity pathways in the National Electricity Plan (RUKN) which integrate medium and higher renewable energy penetration in various electricity systems; and
- Adopt an ambitious long-term strategic plan with clear intermediate targets for renewable energy expansion, supporting policies and streamlined implementation at national, provincial and local levels.

photo: Jeneponto Wind Farm / ESDM

Bibliography

Australian Energy Market Operator, 2018. Australian National Transmission Network Development Plan 2027. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

Bloomberg New Energy Finance (BNEF), 2017. Asia Pacific LCOE Update

Bjarne Bach, 2017. Technology Data for the Indonesian Power Sector, December 18, 2017, 1–140.

Danish Energy Agency, 2016. Wind Resource Map. http://help.emd.dk/mediawiki/images/3/30/Indonesia100m.jpg

Energy and Mineral Resource Ministry of Indonesia (ESDM), 2016. Energy Outlook 2016.

Energy and Mineral Resource Ministry of Indonesia (ESDM), 2017. Peluang investasi dan potensi pengembangan Energi Baru Terbarukan Indonesia, Berdasarkan Peraturan Menteri ESDM Nomor 12 Tahun 2017, tentang Pemanfaatan Sumber Energi Terbarukan untuk Penyediaan Tenaga Listrik. Jakarta

Grid System Operator, 2018. System Demand Profile. https://www.gso.org.my/LandingPage.aspx

International Hydropower Association, 2016. Hydropower Status Report 2016.

Indonesian Secretariat General of the National Energy Council (DEN) and the Danish Energy Agency (2017). Technology Data for the Indonesian Power Sector – Catalogue for Generation and Storage of Electricity

International Energy Agency, 2018. World Energy Outlook 2018. https://webstore.iea.org/download/summary/190?fileName=English-WEO-2018-ES.pdf

Kaliapa Kalirajan and Arif Syed, 2018. The Indonesian Energy Technology Assessment (Ieta), November 2, 2018, 1–165.

Pfenninger, Stefan and Staffell, Iain, 2016. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, pp. 1251-1265. doi: 10.1016/j.energy.2016.08.060

Richter, Alexander. 2018. http://www.thinkgeoenergy.com/indonesia-reaches-1925-mw-installed-geothermal-power-generation-capacity/

Schlegl, Thomas Dr., Kost, Christoph Dr., 2018. Stromgestehungskosten Erneuerbare Energien. May 15, 2018, 1–44

Solargis, 2018. Solar Resource Map of Indonesia. https://solargis.com/maps-and-gis-data/download/indonesia

Staffell, Iain and Pfenninger, Stefan, 2016. Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output. Energy 114, pp. 1224-1239. doi: 10.1016/j.energy.2016.08.068

The Commonwealth Scientific and Industrial Research Organisation, 2018. CSIRO GenCost 2018 : Updated projections of electricity generation technology costs

Appendices

Appendix A: PLEXOS Modelling

Much of the modelling of electricity systems and markets around the world as well as the Australian National Electricity Market (NEM) has been conducted using a commercially available electricity market simulation platform known as PLEXOS provided by Energy Exemplar (www.energyexemplar.com). This software translates the technical and microeconomic parameters of key power system components (generators, transmission lines, loads) into a single optimisation problem and then solves it. It can therefore be used by a range of users with varying degrees of sophistication.

PLEXOS is a mature, and well-respected modelling package and which is currently in use in similar modelling-related research, including modelling the impact of electric vehicles on Ireland's electricity market. Furthermore, PLEXOS can provide a highly accurate prediction of prices and has been used to model market behaviour following the introduction of carbon prices.

PLEXOS' least cost expansion algorithm and planning tools, as used in this study and by the independent Australian Energy Market Operator, AEMO , provides the optimal generation capacity mix given the current and forecasted policy constraints.

The core implementation of optimisation algorithms which drive this software platform are primarily Linear Programming (LP), and Mixed Integer Programming (MIP). Furthermore, the platform uses a number of third party well tested industrial solvers such as Gurobi, CPLEX (IBM) and Xpress-MP to perform optimisation.

PLEXOS utilizes these solvers in combination with an extensive input database of regional demand forecasts, transmission line thermal limits and generation plant specifications to produce marginal costs, generator output level, and generator commitment schedules.

Below we now provide a short overview of the methodologies that PLEXOS uses to simulate the electricity market and to evaluate its optimal expansion.

PLEXOS breaks down the simulation of the NEM into a number of phases which range in scope and scale. These time-scales range from: year-long generation expansion planning and constraint evaluation; security and system supply requirements; network expansion down to 30 minute dispatch and market clearing. The operation and the interaction between these modelling phases is shown in.

[15] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

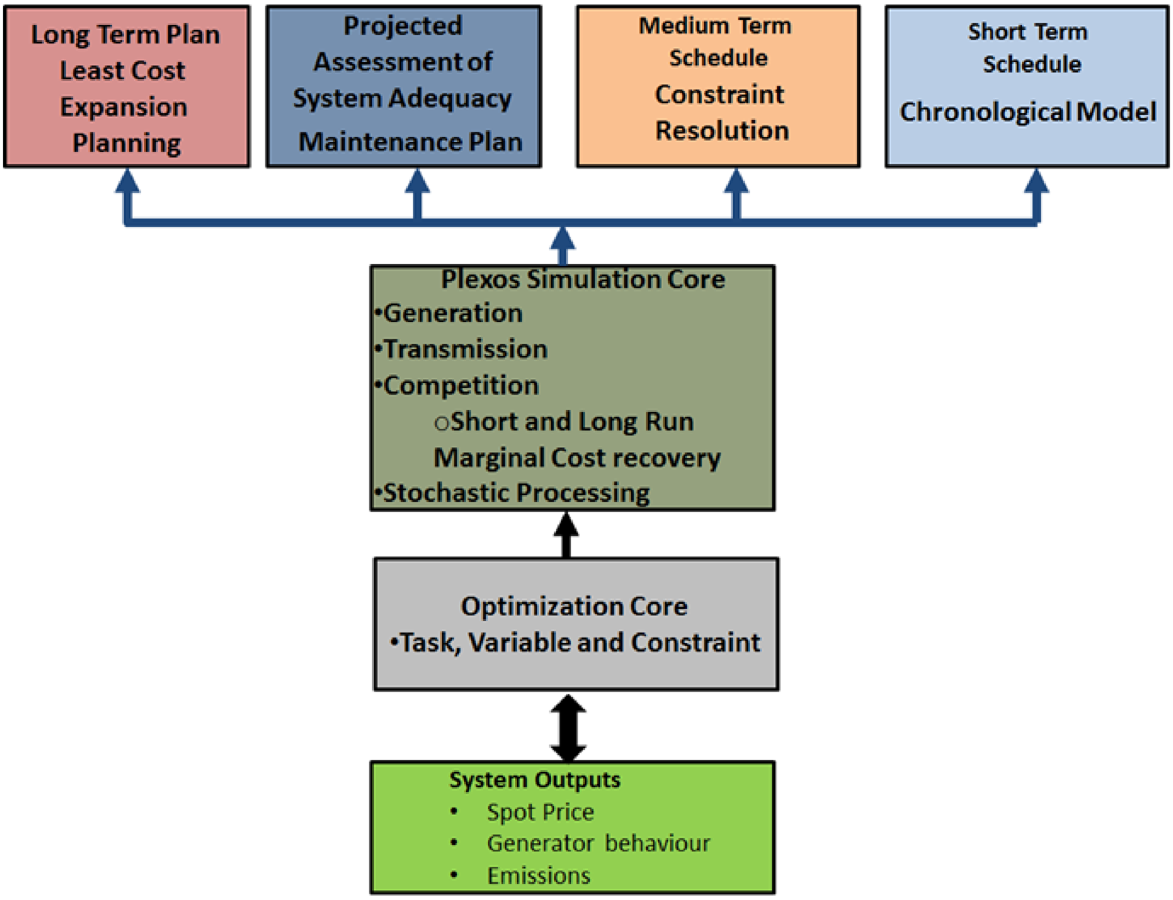


Figure 36: PLEXOS Simulation Core

The sequence of modelling operations is shown in **Error! Reference source not found.** below.

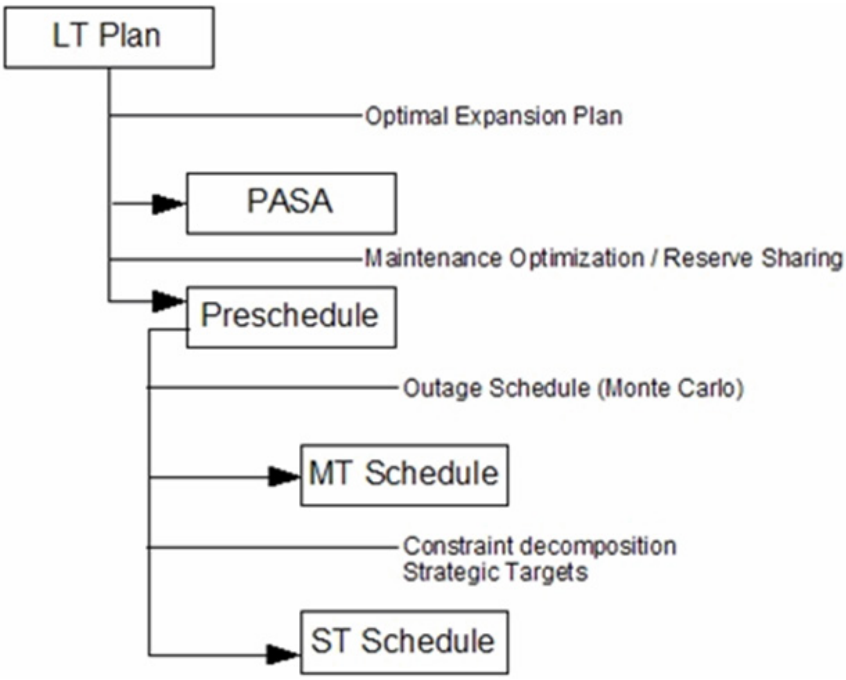


Figure 37: Plexos modelling sequence

We shall now explore briefly the operational aspects of PLEXOS and the methodologies it employs to simulate the electricity market.

LT Plan

The long-term (LT) planning phase of the PLEXOS model establishes the optimal combination of new entrant generation plant, economic retirements, and transmission upgrades which will minimize the net present value (NPV) of the total costs of the system over the planning horizon (as detailed in **Error! Reference source not found.**). Plexos can model a range of different types of expansions/retirements and other planning features within the LT Plan. In this study we utilized only the following:

- Building new generation assets (including multi-stage projects)

However, it is worth noting for future more detailed studies LT Plan can also model:

- Optimal retirement of existing generation plant
- Upgrading the capacity of existing transmission lines
- New build transmission line infrastructure (including multi-stage projects).

Furthermore, the PLEXOS least-cost expansion planning phase also allows the tactical inclusion of global and domestic policy drivers into its input data set. While the scenario development capability of PLEXOS is an important issue into its operation, the parametrization and input are user-defined and labour intensive.

MT Schedule within LT Plan Phase

The Medium Term (MT) Schedule can be used stand alone to speed up operational models but is also applied within the long term LT Plan phase is a model based on Load Duration Curves (LDC) (also known as load blocks), that can run on daily, weekly or monthly resolutions which includes a full representation of the power system and major constraint equations, but without the complexity of individual unit commitment. The MT Schedule can model constraint equations including those that span several weeks, or months of a year. These constraints may include:

- Energy limits
- Long term storage management to model pumped-hydro schemes with or without water inflows.
- Emissions abatement pathways.

Each constraint is optimized over its original timeframe and the MT to ST Schedule's bridge algorithm converts the solution obtained (e.g. a storage trajectory) to targets or allocations for use in the shorter step of the ST Schedule. The LDC blocks are designed with more detailed information concerning peak and off-peak load times and less on average load conditions, thus preserving some of the original load variability.

The solvers used by PLEXOS will then schedule generation to meet the load and clear the offers and bids it generates, inside these discrete blocks. System constraints are then applied, except those that define unit commitment and other inter-temporal constraints that imply a chronological relationship between LDC block intervals. The LDC component of the MT Schedule maintains consistency of inter-regional load profiles which ensures the coincident peaks within the simulation timeframe are captured. This method is able to simulate over long time horizons and large systems in a very short time frame. Its forecast can be used as a stand-alone result or as the input to the full chronological simulation ST Schedule.

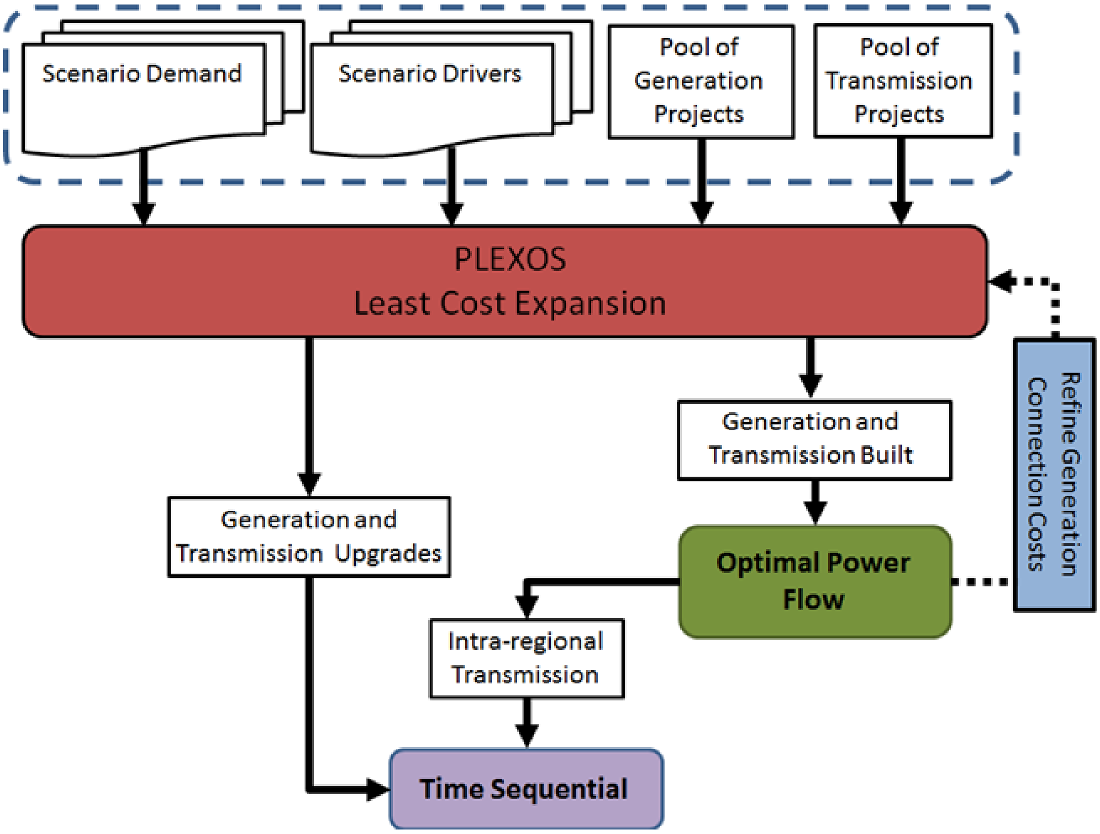


Figure 38: PLEXOS Least Cost Expansion Modelling Framework

Transmission Flow and Optimal Power Flow Solution

In order to model the flow of power through transmission there are several levels of precision use in Plexos. The simple transport model, that takes into account thermal transmission constraints only, and the DC Optimal Power Flow which requires detailed transmission network electrical data such as line impedances.

However, for the purpose of this broader analysis, the simplified transmission flow model, focusing on net transfer capacities between provinces is sufficient for taking into account power transport restrictions and needs between regions. It is able to compute locational marginal avoided prices (LMP) which in a cost based economic dispatch model reflect avoided short run marginal costs of generation at a given transmission node and can also model transmission marginal losses as well as congestion throughout the system. The congestion modelling results are an indicator of long-term constrains which may require capacity upgrades in the future and show the value of locational investment in generation.

PASA

The Projected Assessment of System Adequacy (PASA) schedules maintenance events such that the optimal generation capacity is available and distributed suitably across interconnected regions. The PASA phase of the model allocates/samples discrete and distributed maintenance timings and random forced outage patterns for generators and transmission lines. This ability to sample forced and planned outage patterns allows for uncertainty in generation plant availability and informs the LT Plan expansion phase of the model of further capacity requirements.

ST Schedule

The Short Term (ST) Schedule is a fully featured, chronological unit commitment model, which solves the actual market interval time steps and is based on mixed inter programming. The ST Schedule generally executes in daily steps and receives information from the MT Schedule which allows PLEXOS to correctly handle long-run constraints over this shorter time frame.

PLEXOS models the electricity system central dispatch and pricing (LMP) for each transmission node. This is achieved by determining which power stations are to be included for each dispatch interval in order to satisfy forecasted demand.

To adequately supply consumer demand, PLEXOS examines the variable operating costs of the various generators (combination of fuel cost, heat-rate/efficiency, and additional variable O&M costs) and the commitment characteristics of the generators (start-up cost, minimum operating period if started, minimum off-line period and so forth) and finds a minimum commitment and operation schedule for the generators. This centralised unit commitment and scheduling algorithm uses a mixed integer linear programming optimisation method and takes into account the physical transmission network losses and constraints can serve load.

For the purposes of this study we split each day into 24 hourly periods, and the scheduling algorithm begins with the least cost generator and stacks the generators in increasing order of their variable costs, while taking into account the transmission losses and constraints as well as the commitment characteristics described above until it dispatches sufficient generation to supply the forecasted demand. The cost of the marginal generating unit at each time interval determines the locational marginal price signal (LMP) of electricity at each node for a 1-hour period.

Institute for Essential Services Reform
Jalan Tebet Barat Dalam VIII No. 20 B
Jakarta Selatan 12810 | Indonesia
T: +62 21 2232 3069 | F: +62 21 8317 073
www.iesr.or.id | iesr@iesr.or.id

@IESR @iesr.id