Enhancing Indonesia's Power System

Pathways to meet the renewables targets in 2025 and beyond

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Abstract

This report was prepared on the basis of the framework for collaboration established by the International Energy Agency (IEA) and the Ministry of Energy and Mineral Resources (MEMR) of Indonesia on the topic of power system enhancement and renewable energy integration, and in support of the implementation of the upcoming Presidential Decree on renewable energy. It is part of the assistance provided by the IEA towards Indonesia's efforts to reform its energy sector and is consistent with IEA's forthcoming Energy Sector Roadmap to Net Zero Emissions in Indonesia. The overarching objective of the assignment was to assist Indonesia in tackling short-term power system challenges, by achieving key targets such as reaching a 23% share of renewable energy in the national electricity mix by 2025 in a secure and affordable fashion, and by making grids progressively smarter. The assignment included the organisation of a number of workshops for Indonesian stakeholders and a techno-economic study performed by the IEA. It benefited from the support of the state-owned utility Perusahaan Listrik Negara (PLN). This public report summarises the information gathered from the workshops and presents the results of the study in a set of recommendations for Indonesia.

Acknowledgements, contributors and credits

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Executive summary

Indonesia is a fast-growing economy, expected to become the 4th largest in the world by 2050. To meet the growing energy demand, the government has set ambitious sustainability targets and pledged to meet net zero emissions by 2060 or earlier. The power sector will play a major role in the energy transition, but is today the country's largest contributor to emissions from fossil fuel combustion. Over 60% of the electricity is supplied by a young fleet of coal-fired power plants whose installed capacity will meet a significant share of demand for years to come unless steps are taken now to mitigate their emissions. Gas currently represents almost 20% of electricity generation.

Indonesia has abundant natural resources and a huge potential for renewables, especially hydro, geothermal and solar PV. The national electricity plan states a target 23% share of renewables in the electricity mix by 2025 (up from 14% in 2021). To meet this target, the Electricity Supply Business Plan of the state-owned utility PLN (RUPTL 2021-2030) states it will meet the target with new hydro, geothermal and biofuel-firing capacities, and with biomass co-firing in coal plants. Implementing the plan may be challenging due to delays in the construction of these large generation projects. The plan forecasts relatively little use of solar PV due to the currently higher cost of this technology in Indonesia. Globally, however, solar PV has become increasingly competitive and its deployment can be quite rapid thanks to short construction times. This recently prompted the government to draft a new regulation promoting rooftop solar as a way to meet the 23% target.

This leads to the main research question in this study: could a higher share of solar PV fill the gap and help meet the 2025 renewables target?

The study focuses on the two main systems of Java-Bali and Sumatra, where 80% of the demand is located, and assesses their performance across a number of scenarios in terms of system behaviour, costs and emissions.

The central scenario of the study assumes that all uncommitted and unallocated capacity from the RUPTL, which includes 2.5 GW of new sources of renewable (RE), and the bioenergy portion of designated co-firing capacity would be replaced by utility-scale solar PV. This would require solar PV to reach a capacity of 17.7 GW (against 2.8 GW in the RUPTL) and an annual share in electricity of 10% (against 2% in the RUPTL) in the combined systems of Java-Bali and Sumatra in 2025. Even though such a capacity deployment looks ambitious, the scenario serves as an illustration of the potential role that increasing shares of variable renewables could play to help Indonesia reach its objective to attain a decarbonised and diversified electricity mix.

The main finding is that the existing assets in Java-Bali and Sumatra are capable of accommodating a 10% share of solar electricity by 2025 using flexibility means existing in the system. The coal and hydro plants are completely capable of delivering the needed flexibility and continue to ensure system stability and adequacy. A relatively high level of PV curtailment in Sumatra (14% yearly) is however observed, at periods of low demand and high solar infeed due to the contractual inflexibility of power purchase agreements (PPAs), as explained further. No investment in additional grids or storage capacity is required. However, this amount of variable generation requires updates to operating practices such as the appropriate forecasting and representation of these forecasts in system operation decisions, and the ability to monitor and control the operation of solar PV plants, including the ability to curtail where necessary.

On the cost side, the picture is more nuanced. Solar PV brings fuel savings from both fossil fuels (5.5-7%) and biomass (which comes at a premium) but the current regulations in Indonesia do not allow solar PV to compete in the short term when considering the total system cost. However, the authorities have options. Long-term plans for PV deployment would allow a local industry to develop and offer cheaper rates. Removal of subsidies to coal generation and the introduction of carbon pricing would further improve the business case of all renewable sources. Given the focus of the study on 2025, these longer-term initiatives are not studied in detail but could be the subject of a further study. Another aspect not included in this study is the benefits of enhanced grids and interconnections, such as the expected interconnection between Java-Bali and Sumatra in 2028. The role that increased interconnection among Indonesia's main islands could play in the long term is addressed in IEA's upcoming Energy Sector Roadmap to Net Zero Emissions in Indonesia.

A key barrier to accommodating variable renewables in the Indonesian power system is contractual inflexibility. Take-or-pay (ToP) obligations in PPAs between PLN and independent power producers (with guaranteed offtake obligations) and in fuel supply contracts for gas generators reduce incentives for thermal units to be flexible and affect the overall efficiency of the system. The PPA constraint is significant since the capacity of coal IPPs in Java-Bali is equal to two-thirds of the peak demand in 2025. With the assumption of a 60% guaranteed offtake each year, this significantly reduces the room in the generation mix for renewables. These contractual constraints are a barrier not only to variable renewables but also to any new renewable capacity, even dispatchable (hydro, geothermal), and lead to higher system costs. Removing these constraints, at least partially, would therefore provide room for renewables, reduce costs and help reduce emissions. To provide concrete recommendations on the contractual structures and amount of contracts to revise, more contractual data would be required.

The study does not look in detail at the role of biomass co-firing, a key contributor in PLN's plans to meet the 23% target in 2025. It notes, however, that biomass co-firing in PLN's existing coal plants at low blending rates (10-20% as currently considered, as these require no retrofit of the assets) may exacerbate the coal dominance in the electricity mix. Reliance on a significant share of biomass generation through co-firing in selected plants as specified in the RUPTL would require these plants to run almost flat out, while for every unit of energy from biomass, nine units from coal are forced into the system. This reduces the system flexibility and increases operating costs through interactions with other contractual inflexibilities such as gas ToP contracts. A more thorough study would be required to assess the role of biomass in Indonesia's electricity mix.

The study also looks at the role of electrification of end-uses, like cooking and road transport, which are part of the government strategy to decarbonise the economy, reduce oil imports and improve air quality and emissions. Given the over-sized thermal capacity, increased electricity demand reduces the curtailment of solar PV (mainly in Sumatra) but also leads, in Java-Bali, to an increase in power sector emissions, supporting the need to decarbonise electricity as end-uses are electrified. Despite this, overall emissions are still reduced with the electrification of road transport, driven predominantly by efficiency gains in the move from diesel internal combustion engines to electricity for two- and three-wheelers.

The overall conclusion is that, from a system integration perspective, Indonesia can aim for higher shares of renewables than those listed in the current plans for 2025 and beyond, especially when considering a mix of variable renewables and other dispatchable technologies. However, investment in these renewable capacities faces the risk of low-capacity factors due to the very high amount of thermal capacity in the system with inflexible contractual structures. A priority for the Indonesian power sector is to review the contractual arrangements, while respecting investors rights, and ensure that the thermal fleet is used as closely to actual technical capabilities as possible.

Key recommendations

- The power sector should put renewables, in particular solar PV, at the centre of planning and start adapting operating practices to enable more generation from variable renewables.
- The authorities should take actions to improve the financial competitiveness of solar PV with respect to other technologies in Indonesia. In the short term, constraints such as the local content might be reconsidered.
- The authorities could also take wider action to level the playing field between coal and other technologies by removing the implicit and explicit subsidies to coal, for example the price cap on coal supply, and supporting a shift towards low-carbon sources with some form of carbon pricing.
- The power sector should make best use of the current assets in the system and allow or incentivise the generation fleet to operate according to its technical capabilities.

- The authorities should prepare new contract structures with embedded flexibility for all new PPAs and fuel supply contracts. In addition, to complement the upcoming coal phase-out programmes, they should consult with stakeholders in order to design an approach that brings additional flexibility from existing generation assets.

Chapter 1. Introduction

Meeting Indonesia's target of a 23% share of renewables in the electricity mix by 2025

Indonesia is today the seventh largest economy in the world, the twelfth largest energy consumer and the ninth largest emitter of CO_2 from fuel combustion. Its economic growth over the next decades will be spectacular, going from a GDP per capita of around USD 13 000 in 2021 (which stands at 70% of the global average), to USD 40 000 by 2060, a level equivalent to today's Japan, taking it to the range of advanced economies, and within the top five global economies when total GDP is considered.

In 2021, Indonesia announced a commitment to achieve net zero emissions by 2060, or earlier with support from advanced economies. The measures that could be taken to achieve this target include introducing energy efficiency measures, increasing the share of renewables, reducing the use of fossil fuels, increasing the adoption of electric vehicles and electrification of residential end-uses. The transformation of the power sector would therefore be critical in achieving this goal.

Emitting 224 million tonnes of CO_2 in 2019, the power sector in Indonesia is the country's largest emitter, accounting for 38% of emissions from fuel combustion. Coal is the largest means of power generation, accounting for around 60% of the country's total electricity output. The emissions intensity of Indonesia's power sector is highest among the Southeast Asian countries, at 760 tonnes of CO_2 per kWh in 2019. The policies and regulatory frameworks of the power sector therefore need to be realigned towards the net zero goals. In the short term, in its National Electricity General Plan (RUKN), the Directorate General of Electricity (DGE) under the MEMR set a target to achieve at least a 23% share of renewables in the electricity mix by 2025 (up from around 14% in 2021). While Indonesia has substantial renewable energy potential, particularly geothermal, hydro and solar generation, only a small proportion has been utilised or planned, offering a range of options to decarbonise the power sector.

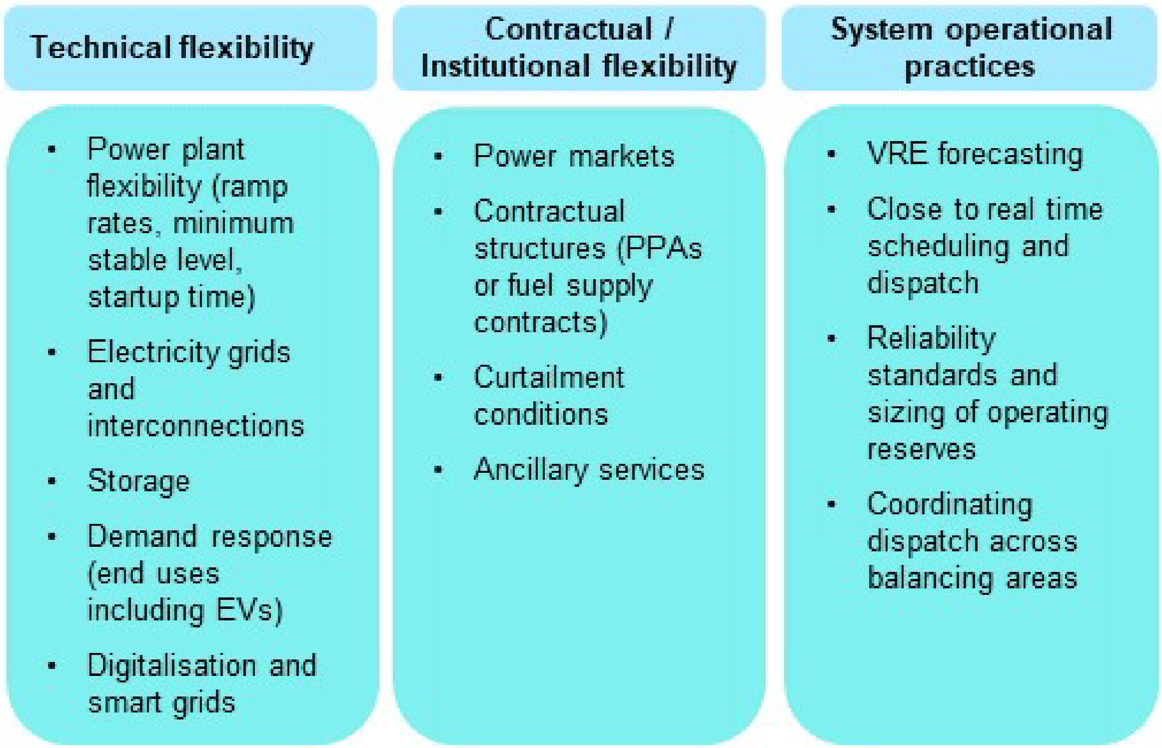
Indonesia is the largest archipelago in the world and there are significant differences among the islands. Java is the most populated island and its system, interconnecting the three islands Java-Madura-Bali (hereafter Java-Bali or JVB) is by far the largest power system. Together with neighbouring island Sumatra (SUM), these two systems represent 80% of Indonesia's electricity demand. Until these two systems are interconnected (from 2028 at the earliest), Java-Bali and Sumatra are distinct systems with different features. Java-Bali is a denselypopulated island with a coal-dominated electricity system while Sumatra is a more rural island with a high potential for solar and hydro power. As interconnections between the islands grow in the future, Sumatra has the potential to play a role as a renewables hub. Therefore, an examination of Java-Bali and Sumatra brings to light the many and diverse potentials and challenges relating to renewables growth in the Indonesian power sector, while already representing four-fifths of the country's electricity demand.

Power system flexibility to support clean energy transitions in Indonesia

Although Indonesia has high potential for hydro and geothermal generation, solar PV is expected to play a growing role. Currently, solar PV comes at higher costs than other renewable technologies. However, wind and solar PV are expected to account for a growing share of the new additions globally as their cost competitiveness continues to increase. . Integrating variable renewables (VRE), like wind and solar PV, into the power system can be challenging due to their unique technical properties: variability because the output varies over time depending on the availability of primary resources (wind or sun); and uncertainty as the output cannot be perfectly forecasted, especially at longer lead times. Systems such as in South Australia, Denmark or Ireland, have demonstrated that this challenge can be addressed in cost-effective and reliable ways. To help governments deploy efficient measures in the right order of priorities, the IEA has developed a framework to capture the evolving impacts and understand the challenges of integrating VRE into the power system.

In particular, solar PV produces electricity according to diffuse solar radiation, which is affected by the seasons and of course daylight, requiring other resources to take over in the evening. Higher reliance on solar PV therefore requires sufficient flexibility in the electricity system to keep supply and demand in balance across all relevant timescales, ranging from seasons to hours and minutes. Power system flexibility refers broadly to all the attributes of a power system that allow the system operator to reliably and cost-effectively balance demand and generation in response to variability and uncertainty. Key components of power system flexibility include technical flexibility, contractual/institutional flexibility and operational practices. These components must be considered simultaneously in the effort to enhance system flexibility.

The building blocks of power system flexibility



Report scope and structure

This report focuses on the two largest systems of Java-Bali and Sumatra and how they may evolve by 2025 to meet the target of a 23% share of renewables in the electricity mix. In particular, the ability of these two systems to accommodate more variable renewable energy (VRE) is analysed. Given the significance of these two systems, the differences between them and the nature of the challenges, recommendations can be drawn for Indonesia's power sector over the next decade as it will play a key role in the country's pathway towards carbon neutrality by 2060.

This study has three main parts. Chapter 2 provides the context of the existing Indonesian power sector. It gives a general description of today's power system before diving into the challenges relating to system flexibility that must be addressed for the integration of higher shares of VRE such as solar PV. Chapter 3 focuses on the two largest systems of Java-Bali and Sumatra, which together account for 80% of the country's demand for electricity. It presents a techno-economic analysis to assess the capability and challenges that these two systems face in integrating VRE, to meet the renewable targets of 2025. A central scenario looks at the potential of solar PV to fill the gap between the current trajectory and the target. Alternative scenarios address the electrification of transport and residential cooking – separate but parallel goals of the Indonesian government – and how they can contribute to VRE integration. Another key aspect that is studied is the inflexibility of the current contractual structures for power generation. Chapter 4 builds on the key outcomes from the previous two chapters to identify some measures that would support reaching the short-term sustainability objectives and prepare for more ambitious targets. These measures include enhancements to contractual structures, power system planning and operation practices, and deployment of smart grids.

Chapter 2. Indonesia’s power sector and challenges

Key findings – Power sector in Indonesia

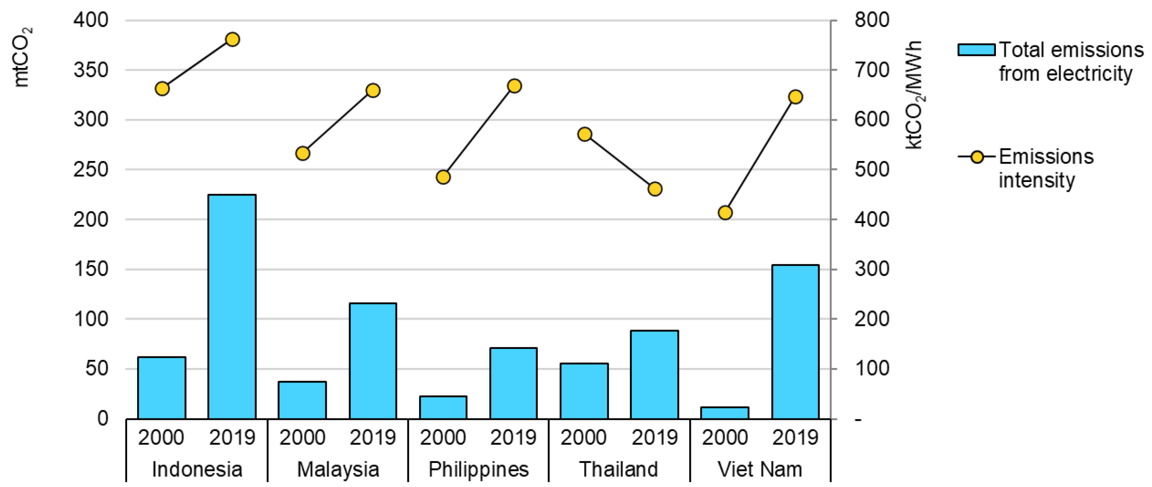
- Over the past few decades, Indonesia’s economic growth and electrification progress have been remarkable, enabling near-universal access to electricity. However, overly optimistic demand growth forecasts and conservative planning practices relying on high generation capacity margins, as well as a lack of interconnections among islands has led to overcapacity of thermal plants, far in excess of peak demand for years to come on the main island of Java.
- Driven by the high share (60%) of coal-fired generation, the power sector represents 38% of Indonesia’s emissions from fossil fuels combustion today, but the MEMR has set an ambitious target for a 23% share of renewables in the electricity mix by 2025 (up from 14% in 2021).
- The RUPTL (Electricity Supply Business Plan) 2021-2030 relies on new hydro and geothermal capacities, and on biomass co-firing in about a third of the coal-fired capacity (at the co-firing rate of up to 10% biomass) to reach the target of a 23% share of renewables in the electricity mix by 2025, but relatively little on solar PV.
- Despite the increased competitiveness of this technology globally, solar PV in Indonesia remains unattractive compared to other technologies due to low deployment levels and local regulations, such as the local content obligation which keeps PV prices high. Regulated fuel and electricity prices result in the need for state subsidies to the state-owned utility PLN and further limit the attractiveness of private investment in new renewable capacities.
- A key barrier to accommodating VRE in the Indonesian power system is contractual inflexibility. PLN has to dispatch the young thermal fleet of coal-fired IPPs according to minimum offtake obligations which cover a significant share of the demand.

Indonesia’s power sector is a major source of emissions…

Indonesia is an archipelago of more than 17 000 islands and with a population of 270 million. The distribution of population and resources among the different island groups is uneven. Likewise, the levels of economic development vary across the different island groups leading to different energy system features. Indonesia is a fast-growing economy with growing energy use. Between 2000 and 2019, GDP grew from USD 395 to 1 049 billion (2015 market exchange prices), while its total primary energy supply grew from 6.53 to 10.09 exajoules (EJ).

Due to the large share of fossil fuel generation, the power sector's CO_2 emissions (224 $MtCO_2$) represent the largest portion (38%) of the country's total emissions from fuel combustion. The emissions intensity of the power sector has increased over the past decades, contributing over 220 million tonnes of CO_2 in 2019.

Power sector emissions and CO_2 intensity in Indonesia and in selected Southeast Asian countries, 2000 and 2019



Source: IEA (2021), World Energy Statistics and Balances.

… but Indonesia has ambitious targets for electricity access and decarbonisation

Indonesia's national energy policy, the *Kebijakan Energi Nasional* or KEN, is a high-level strategy adopted in 2014, which lists targets for 2050. The main **drivers for this energy policy** are energy security and energy independence, to be achieved through energy conservation and supply diversification. It is important to note that the current energy policy, which pre-exists the net zero pledge, aims to **reduce the role of oil in the primary energy supply** but is open to expanding coal and gas due to their abundance in the country. The targets for renewables in primary energy are aligned with the ASEAN targets.

Selected targets under the 2014 National Energy Policy

	Unit	2020	2025	2050
Primary Energy Supply	EJ		>16	>42
Share of Primary Energy				
New and renewable energy	%		>23	>31
Oil	%		<25	<20
Coal	%		>30	>25
Gas	%		>22	>24
Installed power capacity	GW		>115	>430
Electricity access rate	%	100		
Electricity consumption per capita	kWh/capita		2 500	7 000

Note: New and renewable technologies include non-renewable sources such as nuclear, hydrogen, coal bed methane, liquefied coal and gasified coal.
Source: Government of Indonesia (2014), National Energy Strategy (KEN).

To put these targets into the perspective of the most recent data relative to year 2020, almost full electricity access was achieved and the installed power capacity amounted to around 72 GW. Electricity consumption per capita was slightly less than 1 000 kWh and total energy supply was around 10 EJ. The discrepancy between these last values and the targets illustrates the excessively optimistic demand forecasts, an issue that is further explored below.

In its updated Nationally Determined Contribution (NDC), **the country aims to reduce total economy-wide emissions** to 2 034 $MtCO_2$-eq (unconditional) or 1 683 $MtCO_2$-eq (conditional on international support) by 2030. This entails achieving emissions for coal, oil, gas and power of 1 355 $MtCO_2$-eq (unconditional) or 1 223 $MtCO_2$-eq (conditional) from a business-as-usual assumption of 1 669 $MtCO_2$-eq by 2030.

For the power sector, a peak of 349 $MtCO_2$-eq is planned by 2030 in order to reach net zero emissions by 2060, up from 224 $MtCO_2$-eq in 2019. In 2021, the government announced in its NDC the goal to meet net zero emissions by 2060, or sooner with support from developed countries. Five strategies were identified to achieve this target: 1) increasing the share of renewables, 2) reducing the use of fossil fuels, 3) promoting electric vehicles, 4) electrification in the residential and industrial sectors and 5) utilising carbon capture, utilisation and storage (CCUS).

The power systems across the country are very diverse. Highly developed provinces such as Jakarta, Central Java and Bali have electricity access rates of 100%, while the less developed eastern provinces (in Nusa Tenggara) have rates just below 90%. Diesel-based generators are common in the isolated small-island grids, while coal, hydro and geothermal resources are prevalent in the larger systems of Java-Bali and Sumatra.

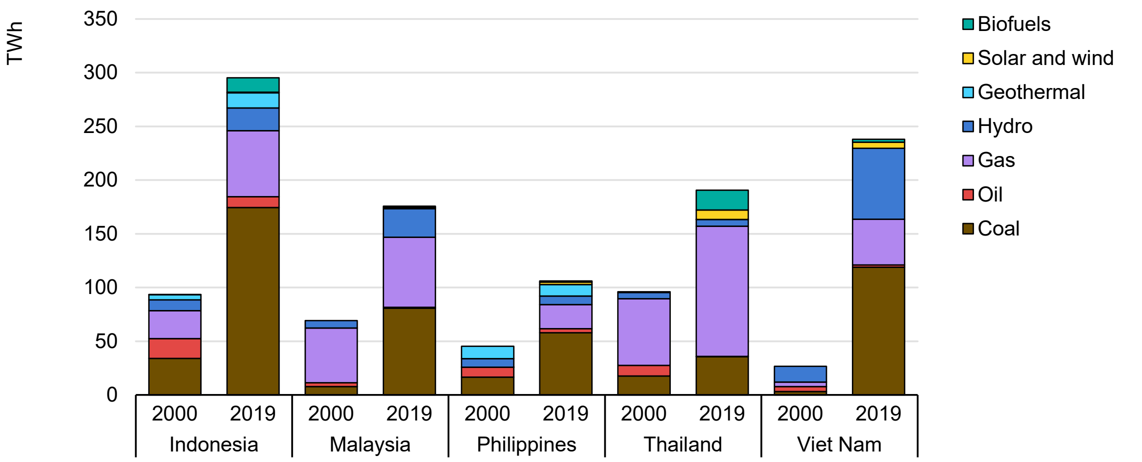
Population, electricity consumption and electricity access rates in the major island groups, 2021

	Population (million)	Consumption (GWh)	Electricity access rate (%)
Java-Madura-Bali	156	175 035	99.60
Sumatra	58	38 111	99.69
Kalimantan	16	11 352	98.86
Sulawesi	20	11 423	99.23
Maluku, Papua, Nusa Tenggara (MPN)	18	6 192	94.13
Total	**268**	**242 113**	**96.7**

Note: Electricity access rates in the different provinces of the eastern island group MPN vary greatly.
Source: PLN (2021), RUPTL 2021.

Indonesia's abundant resources for power generation enabled it to increase **electricity access rates** rapidly despite the higher costs associated with archipelagic layouts. Most notably, the role of coal expanded from a 36% share in 2000 to almost 60% by 2019, when total generation grew from 93 TWh to 294 TWh.

Generation in Indonesia and in selected Southeast Asian countries by fuel, 2000 and 2019



Source: IEA (2021), World Energy Statistics and Balances.

The **transmission system** is mostly made up of 150kV transmission lines, with a limited number of high voltage 500kV lines found only in the Java-Madura-Bali system, but which form the strong backbone of its transmission network. As the transmission system is long and thin, voltage stability is a concern, especially within the 150kV network. In 2005 and 2019, transmission outages led to widespread blackouts in Java.

Apart from Java-Madura-Bali, the islands currently have separate systems. However, there are plans to build more interconnections between islands and with the neighbouring countries in the future under the ASEAN Power Grid (APG). The first planned interconnection is between Java and Sumatra, from 2028. These interconnections and further reinforcements to the transmission systems will play a key role in enabling renewables-generated power to be shared across larger balancing areas.

Transmission lines in the Java-Bali and Sumatra system

This map included is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: MEMR geoportal.

The power sector is structured around state-owned utility PLN as the single buyer

Indonesia's **power sector** is currently regulated by Law 30/2009, or the 2009 Electricity Law. It allocates roles and responsibilities to the institutions and market players, and defines rules for permitting, tariff setting and planning of the power sector.

The MEMR or Kementerian Energid dan Sumber Daya Mineral (ESDM) is the main policymaker and regulator for energy affairs, including electricity.

The DGE under the MEMR specifically focuses on the development of the electricity sector and coordinates with other directorates such as oil and gas, coal and minerals, and new and renewable energy. The national electricity policy is set by the DGE through the National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional* or RUKN) and takes input from KEN and from the National Energy Master Plan (*Rencana Umum Energi Nasional* or RUEN). It is an indicative 20-year demand outlook with government policy targets such as electricity access and interconnectivity rates, share of renewables and uptake of electric vehicles. The DGE set the **goal for at least a 23% share of new and renewable energies (NRE) in the electricity mix by 2025**. The electricity system transformation also needs to fulfil the three key sustainability pillars, which are *Availability* (security of supply), *Affordability* (least cost) and *Acceptability* (environmental sustainability).

The 2009 Electricity Law designates PLN, a state-owned vertically-integrated utility, as responsible for generation, transmission, distribution and retail. Several attempts have been made to restructure and unbundle the electricity sector but these have been unsuccessful. The Constitutional Court stated in 2015 that the unbundling of electricity services would not be permitted if it meant that the state would have less control over the sector as a result.

Several independent power producers (IPPs) are allowed to participate by selling energy directly to PLN, which acts as a **single buyer**. Under the 2009 Electricity Law, private businesses may be given the right to provide electricity for public use through the electricity business licences or *Izin Usaha Penyediaan Tenaga Listrik* (IUPTL), especially for renewable energy projects or those with construction or fuel supply risks. In the Java-Bali system, the generation capacity from IPPs in 2025 will be about 19 GW, accounting for a 54% share. However, several IPPs reported difficulties in terms of inconsistent application of regulations as well as lack of transparency and clarity in PLN's rules for procuring electricity from power plants,[1] resulting in limited private participation in the power sector, and subsequently the limited development of renewable energy.

In contrast, transmission and distribution infrastructure remains within the ownership of PLN. Private operators are allowed to undertake build-operate-transfer (BOT) or build-lease-transfer (BLT) schemes in order to alleviate the investment burden of PLN in grids while retaining the latter's control.

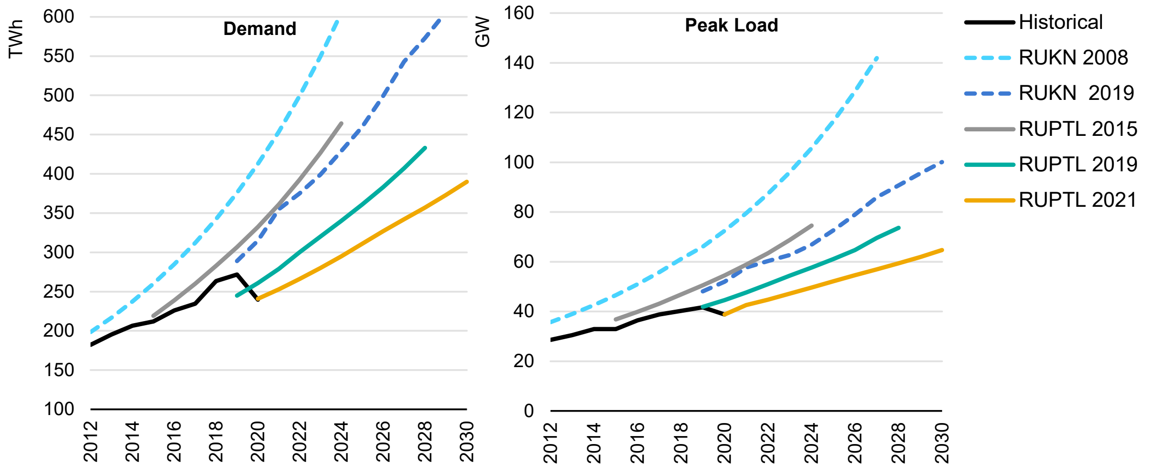
[1] OECD (2021), Clean Energy Finance and Investment Policy Review of Indonesia, Green Finance and Investment, OECD Publishing, Paris, https://doi.org/10.1787/0007dd9d-en

Overly optimistic demand forecasts and conservative reliability standards created generation overcapacity

Under the 2009 Electricity Law, **electricity supply business planning** (*Rencana Usaha Penyediaan Tenaga Listrik* or RUPTL) is drafted by PLN every year in coordination with other stakeholders and has to be approved by the MEMR. The latest RUPTL was issued in October 2021 for the period 2021-2030 (hereafter, RUPTL 2021).

It is important to note that demand projections, both the peak demand and annual consumption, of Indonesia have been consistently overestimated. This is a common problem among utilities under regulatory frameworks allowing risks (costs) to be passed on to consumers or tax payers. The demand forecast has been a top-down approach based on historical elasticities and GDP growth for each sector. In addition to the observed over-estimation of economic growth, this approach is not able to reflect energy efficiency improvements.

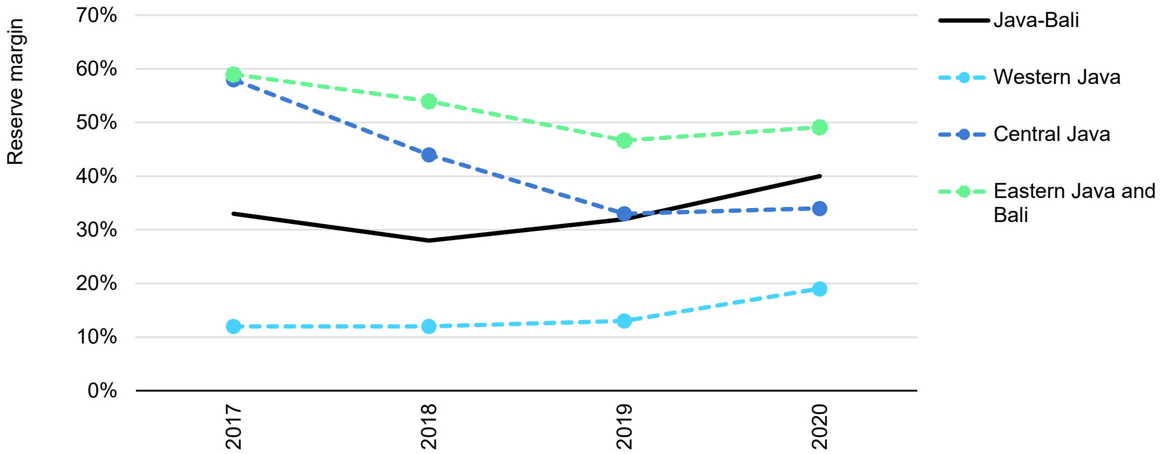
Historical data and projections of demand (left) and peak load (right) in the RUKN and RUPTL, 2011-2030



Source: IEA analysis of MEMR (2008), RUKN 2008; MEMR (2019), RUKN 2019; PLN (2014), RUPTL 2014; PLN (2019), RUPTL 2019 and PLN (2021), RUPTL 2021.

High demand forecasts contributed to the overbuilding of power plants, which has led to high reserve margins, particularly in central and eastern Java. Excessive capacity unnecessarily increases the system costs of a power system and can delay the uptake of cheap renewable capacity as revenues are prioritised towards payments for existing assets, mainly excess fossil fuel power plants.

Historical reserve margins in the Java-Bali power system



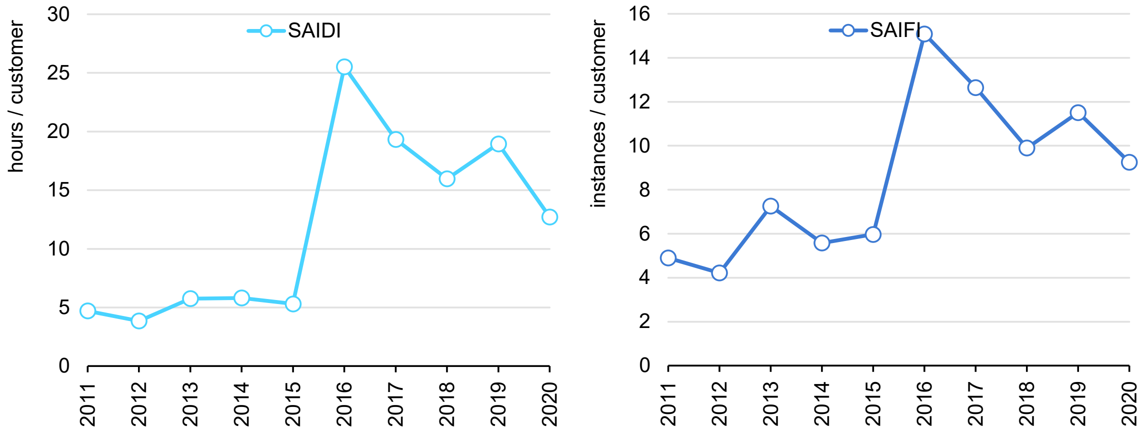
Source: IEA analysis of the RUPTL (2017; 2018; 2019; 2021).

There are several **reliability criteria** that Indonesia has set out in its electricity policy. The main reliability criterion is to maintain the **reserve margin** at a minimum of 35%, which is based on the loss of load probability (LOLP) of less than 0.274%, or one day per year in which the peak demand cannot be met[2] within the area of a control centre unit. The reserve margin criterion is higher than international standards for power systems based on fossil fuels. In Java-Bali, the reserve margin is forecast to be in the range of 40-60% for the next decade. In particular, generation is being built in the western part of the system, where the capital Jakarta is located. Given the high margins in the eastern part of the island, one wonders if grids would be needed instead of generation. Also, moving towards a fully probabilistic method, such as those used in Australia and Texas, would result in lower system costs while maintaining adequate system reliability.

On the distribution side, the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are monitored to assess the reliability of service. Since 2016, the interruptions have been more frequent and their resolution has taken longer, resulting in worse indices. Compared to its ASEAN neighbours, the Indonesian power sector in 2019 had higher values of SAIDI (18.95 hours per year, compared to the ASEAN average of 10.27 hours per year) and SAIFI (11.51 times per year, compared to the ASEAN average of 8.71 times per year). A smart grid programme is now aiming to improve service reliability and reduce the instances and duration of interruptions.

[2] The relationship between the LOLP and the reserve margin is the result of an assessment which depends on a number of parameters such as the outage rate of power plants and the size of the plants relative to the system size. The same LOLP may lead to different reserve margins in different systems. For comparison, a LOLP of one day per year corresponds to margins below around 15% in some US systems.

SAIDI and SAIFI indicators in Indonesia, 2011-2020



Source: PLN (2021), RUPTL 2021.

The main operation principles of PLN are designed to ensure the reliability (credible contingency), cost-effectiveness (economic dispatch and losses) and quality of the system (frequency and voltage excursions). PLN entities act as system operators in their respective territories with the authority to call upon generators to ramp up or ramp down production, or start-up and shut down, to shed load, and to curtail intermittent generation.

The operating practices in Indonesia are deterministic, in line with traditional practices as applied to systems dominated by baseload fossil generation. The power system operates at 50.00 Hz with a normal frequency range of ± 0.20 Hz, with allowable operation during disturbances ranging between 47.50 Hz and 52.00 Hz. The spinning reserve requirement is based on N-1 criterion to cover the loss of the largest unit in the system. Protection schemes including load shedding, under frequency relay and islanding modes, are employed to ensure system stability. The voltage stability standard is maintained at +/- 5% for 150kV and 500kV systems through reactive power management. One of the key challenges in Java-Bali is the voltage stability due to the network topology, being long and thin. For transmission, the country implements static and dynamic N-1 security criteria, ensuring the ability to deliver the same amount of energy based on load if a transmission circuit goes out. As some islands will experience growing penetration of VRE, their system's stability (the ability of the power system to recover from disturbances on very short time scales and maintain the state of operational equilibrium) and reliability criteria, operational standards and contribution of technical assets to provide system services may need to be revised towards more probabilistic approaches.

Indonesia has substantial energy resources but renewables are underutilised

Coal is a strategic resource for Indonesia. It is a major exporter of coal to India, the People's Republic of China (hereafter, "China"), Japan, Malaysia and the Philippines. In 2020, it produced 563.7 million tonnes of coal, exported 405 million tonnes, and consumed 131 million tonnes domestically – 79% of which went to the power sector.

Coal supplies 60% of the electricity demand. Domestic coal supply is secured through a Domestic Market Obligation (DMO) established by Regulation 25/2018 (which supersedes Regulation 34/2009) requiring coal producers to reserve a minimum percentage – which may vary each year – for domestic sales aimed at keeping the cost of electricity low. For 2021, 25% of domestic production was set as the obligation, with USD 70/tonne as a price cap.[3] This local obligation at a set price is in fact a **fuel subsidy that affects the overall efficiency of the Indonesian energy system**. Given the currently high prices on international coal markets, this local obligation also represents an opportunity cost for Indonesia. However, this consideration did not prevent Indonesia from banning coal exports in January 2022 as PLN's reserves were approaching historic lows.

Gas is also a significant resource in Indonesia, and the country exports both pipeline gas and LNG. In 2020, the power sector consumed 12% of total net gas production, while gas itself was responsible for 19% of total power generation.

Indonesia also has significant **renewable energy potential**, but only a small percentage has been realised. Geothermal and hydropower have been the main sources of renewable power generation to date. According to the latest Electricity Supply Business Plan (RUPTL 2021), these two sources combined are expected to contribute to 4.6 GW of the 10.6 GW additional NRE capacity needed to achieve the country's target of a 23% share of NRE in power generation by 2025. IEA's estimates, as well as those of several other organisations (for example, the Renewable Energy Pipeline by the Danish Energy Agency, the Review of Renewable Energy Potentials in Indonesia and Their Contribution to a 100% Renewable Electricity System by TU Delft, Indonesia's Vast Solar Energy Potential by the Australian National University) support much higher potential for wind and solar compared to the RUPTL, but this potential is unevenly distributed across the islands, especially wind power. As for utility-scale PV, the Java-Bali system has a potential in the range of 59 GW, compared to more rural Sumatra which has a potential exceeding 600 GW.

[3] Decree of the Minister of Energy and Mineral Resources Number 139.K/HK.02/MEM.B/2021 on Meeting Coal Needs.

Renewable energy potential according to the RUPTL and IEA, and current installed capacity in Indonesia

	Potential according to RUPTL GW	Installed capacity in 2020 GW	Realisation of potential according to RUPTL %	Potential according to IEA GW
Geothermal	29.5	2.13	7.2	
Hydro	75.1	5.64	7.5	
Mini- / Micro hydro	19.4	0.50	2.6	
Bioenergy	32	1.89	5.9	
Utility-scale solar (4.8 kWh/m² per day)	207.9	0.158	0.08	1 500
Onshore wind	60.6 (≥ 4m/s)	0.154	0.25	500 (≥ 4.5m/s)
Marine	18	0	0	

Notes: Installed capacity includes on-grid and off-grid capacity. Installed capacity of solar does not include solar powered public street lighting (16.04 MW) and solar powered energy saving lamps (10.90 MW).

Sources: PLN (2021), RUPTL 2021; MEMR (2020), Handbook of Energy and Economic Statistics of Indonesia; IEA analysis of the Global Wind Atlas and Global Solar Atlas; and 2020 land-use data from the European Space Agency (ESA) Climate Change Initiative (CCI).

Bioenergy is one of the main focus points for development in the country. There are currently 45 MW of biogas installations planned for 2024, and ongoing trials for biomass use. The trials involve using waste pellets, wood pellets, woodchips, palm kernel shells, sawdust and rice husks. There are plans to make use of different co-firing rates, namely, 6% for pulverised coal (PC), 40% for circulating fluidised bed (CFB) and 70% for stoker-type boilers. One of the challenges in developing biomass co-firing at the existing thermal power plants is the large amount of biomass supply that would be required and the need to deploy the corresponding sustainable supply chain as explained below. Another consideration is the lower efficiency of co-firing in coal plants which increases the total costs of the power system. On the other hand, this type of retrofit would allow the re-use of existing dispatchable assets.

Since 2015, Indonesia has had plans for waste-to-energy, but these are yet to turn in effective generation.

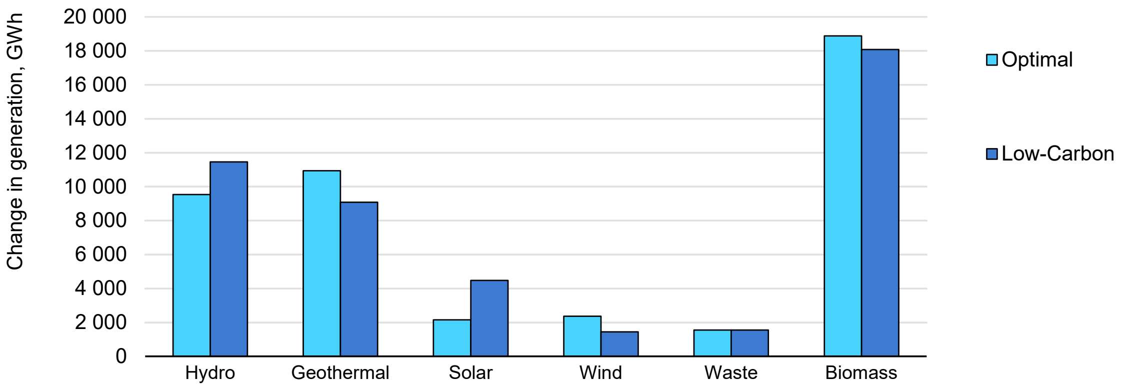
PLN relies on biomass co-firing to achieve renewable target with little use of solar PV

To achieve the targets set by the government, including a 23% share of renewables in the electricity mix by 2025 and emissions reductions, PLN formulated two generation scenarios – optimal mix and low-carbon[4] – for 2021-2030 in the RUPTL. In both of these two scenarios, the renewables growth

[4] PLN's optimal mix scenario for 2030 considers a mix of 64% coal, 11.5% gas, 23% NRE, 0.4% fuel oil and an additional potential for 1.2% NRE. The low-carbon scenario for 2030 considers a mix of 59.8% coal, 15.6% gas and 24.2% NRE.

between 2021 and 2025 would be 45-46 TWh, with biomass taking a large share of growth at around 40-42%, followed by hydro and geothermal at 21-25% and 20-24%, respectively. At the same time, the electricity generated from non-renewables is also expected to grow by 24 TWh. On the other hand, the share of solar PV in 2025 is less than 2% despite its declining costs globally and short installation time, due to the currently high costs of solar PV and PLN's concerns about the variability of VRE.[5]

Growth in renewables generation in the RUPTL optimal and low-carbon scenarios, 2021-2025

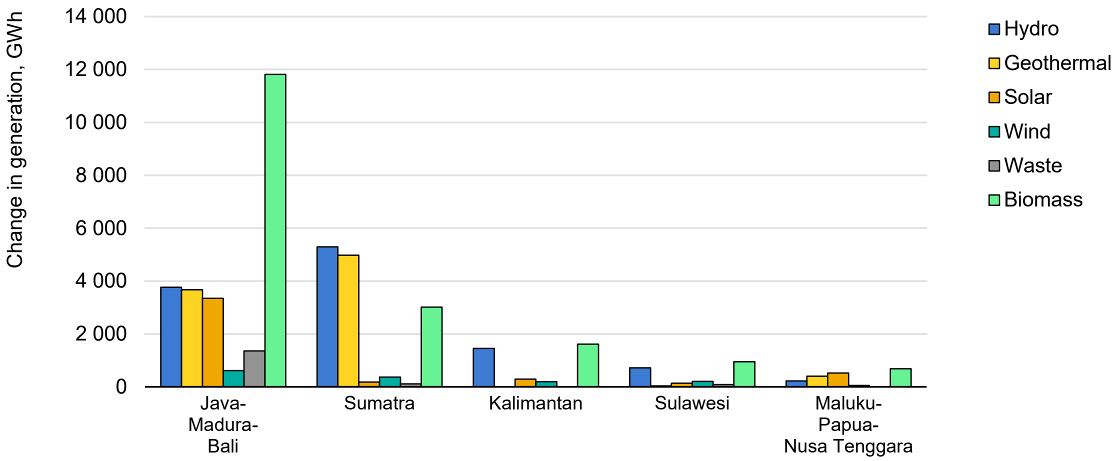


Sources: IEA analysis of PLN (2021), RUPTL 2021.

To achieve its renewable energy targets, Indonesia is aiming to leverage biomass co-firing in its existing coal plants that are located primarily in the Java-Bali system. By 2025, Indonesia expects 13 million tonnes of biomass to be co-fired to achieve the renewable generation required to meet the 23% target. While this volume falls within the IEA estimates of the available wood residues at slightly more than 18 million tonnes in 2025, it illustrates the challenge for Indonesia to deploy a sustainable biomass supply chain to support this target. Co-firing up to 10% would be the maximum rate that Indonesia aims to implement with its existing fleet, and up to 20% in power plants built in the future. These low blending ratios present the advantage of obviating the need for more investment in retrofitting plants.

[5] Tambunan H., et. al. (2018), Maximum Allowable Intermittent Renewable Energy Source Penetration in Java-Bali Power System, 2018 10th International Conference on Information Technology and Electrical Engineering (ICITEE), 2018, pp. 325-328, doi: 10.1109/ICITEED.2018.8534845.

Growth in renewables generation by main island group in the RUPTL Low Carbon Scenario, 2021-2025



Source: IEA Analysis of PLN (2021), RUPTL 2021.

Indonesia also aims to leverage generation from new hydro and geothermal in Java-Bali and in Sumatra. For the 11.5 TWh of hydro and 9 TWh of additional thermal generation needed between 2021 and 2025, the planned additional capacity of 3.16 GW hydro and 1.4 GW geothermal would be sufficient.

The expected growth from wind and solar between 2021 and 2025 is limited at 1.4 TWh and 4.5 TWh, respectively, in the RUPTL. These moderate targets are based on PLN's own assessment of their ability to manage variable generation. The RUPTL considers only utility-scale solar projects. In the meantime however, in order to accelerate the deployment of renewables and meet the 23% target by 2025, the MEMR has drafted a new regulation (MEMR Regulation 26 of 2021) dedicated to rooftop solar, which is expected to come into force shortly.

Power pricing regulation limits attractiveness of renewables investment

PLN and the MEMR use the main indicator *biaya pokok penyediaan* (BPP), the **average cost of production,** as a measure of cost-effective performance of the power sector. This indicator considers the total system costs associated with providing a kilowatt-hour of electricity and is calculated on the basis of average historical accounting.

The total BPP is made up of three components: BPP-*pembangkit* (generation), BPP-*transmisi* (transmission), BPP-*distribusi* (distribution) with generation being a major factor for the total BPP. Each of these factors is calculated yearly at sub-system level and may diverge between regions. In 2020, total BPP (weighted average) was IDR 1348/kWh (USD 92.5/MWh)[6] and BPP-generation was IDR 1027/kWh (USD 70.4/MWh)[7] or 76% of total BPP.

In order to ensure electricity affordability, the MEMR controls the generation component through fuel and electricity purchase price regulation. On the one hand, BPP-generation is used as a benchmark for power purchases from IPPs. On the other hand, the cost of coal is capped at USD 70/tonne through the DMO resulting in about USD 1.82 to 2.13 billion worth of operating costs effectively subsidised by the coal producers. Without this subsidy, the electricity generation cost could be around IDR 100 to 150/kWh (USD 7 to 11/MWh) more expensive.[8]

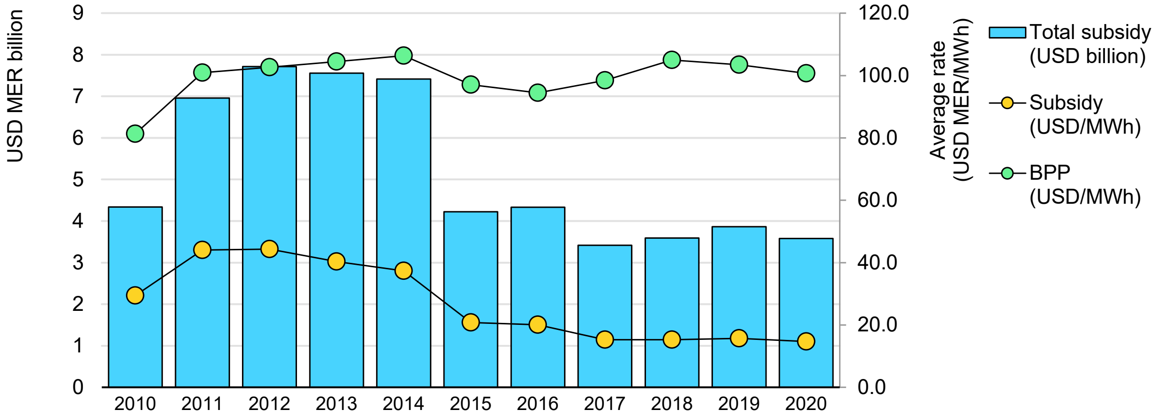
For gas, Regulation 34K/16/MEM/2020 allocates gas volumes to the power sector and Regulation 91K/12/MEM/2020 sets maximum purchase prices. Given the large share of coal in the electricity supply, the resulting BPP-generation of the systems remain low.

As renewables purchase prices are also regulated, it introduces stiff competition with fossil-fuel based generation. Regulation 50 of 2017 amended by Regulation 4 of 2020[9] sets a maximum purchase price for hydro and geothermal of 100% of the current BPP-generation of the local system, while for electricity generated from solar PV, wind, biomass, and ocean wave it is limited to 85% of the BPP-generation. Local content requirements on power infrastructure development (MOI Regulation 52/2012) and specifically for solar PV (MOI 5/2017) are estimated to increase the CAPEX by up to 50% due to the higher module production cost compared to global markets. Hence, regulation based on a purchase price cap that is artificially lowered by coal purchase subsidies limits the attractiveness of renewable investments.

The limited investment in VRE hinders the Indonesian electricity sector from taking advantage of zero marginal costs which can help reduce the subsidies it is currently spending. In addition to coal purchase subsidies, consumer tariffs are also subsidised. To cover the costs of providing electricity to the general public, low-income households, rural, or remote areas, the government provides a direct subsidy to PLN to cover expenses not covered by current consumer tariffs. In recent years, this has ranged between USD 3 and 4 billion.

[6] PLN, Statistics book 2020. 1 USD = 14 582 IDR market exchange rate in 2020.
[7] Decree of the Minister of Energy and Mineral Resources Number 169.K/HK.02/MEM.M/2021 on cost of electricity supply for year 2020.
[8] Article published on Bisnis.com on 23 March 2018 with the title "Coal Prices Set, Electricity Production Costs Can Be Reduced by Rp300/kWh" on the consequences of the capped price on coal for power generation.
[9] Regulation of the Minister of Energy and Mineral Resources number 4 of year 2020 about second amendment to Regulation 50 of 2017 concerning the utilisation of renewable resources for electricity supply.

Historical electricity subsidies, average subsidy rate and BPP, 2010-2020



Notes: BPP = *biaya pokok penyediaan* or average cost of production. MER = market exchange rate. The average subsidy rate is based on total subsidies paid over total electricity sales.
Source: IEA analysis of PLN (2014), RUPTL 2014; PLN (2017), Annual Report 2017; and PLN (2021), RUPTL 2021.

Given that increasing the share of VRE would have system-wide impacts and benefits, it would be important to assess them in the context of these regulatory control points that distort market values. Reflecting the real market value of coal can allow PLN to find a more optimal use for its subsidies such as helping lower the upfront costs of VRE integration. If solar PV displaces coal-fired generation, excess coal could be sold at higher prices on international markets. Currently, the record high prices on coal markets represent an opportunity cost for Indonesia. And although this is short-lived, the prices are expected to stabilise to around USD 20/tonne above the cap in 2022-2024 according to IEA's coal market report (December 2021).

There is untapped flexibility potential in the Sumatra and Java-Bali systems

Key components of power system flexibility include technical flexibility, contractual/institutional flexibility and operational practices. These components must be considered simultaneously in the effort to enhance system flexibility.

Prominent **technical flexibility** resources include power plants (both conventional and variable renewables), electricity grids (including interconnectors), energy storage (pumped hydro and batteries) and distributed energy resources (including demand response and electric vehicles). Grids play a major role in terms of flexibility: they allow the sharing of resources across larger areas, a feature which has even more value for variable renewables as their spatial diffusion helps smooth down variability. Since grids take time to be built, little emphasis is put on grids in the study of Java-Bali and Sumatra in 2025 presented in Chapter 3, but they will certainly play a growing role in the coming decades.

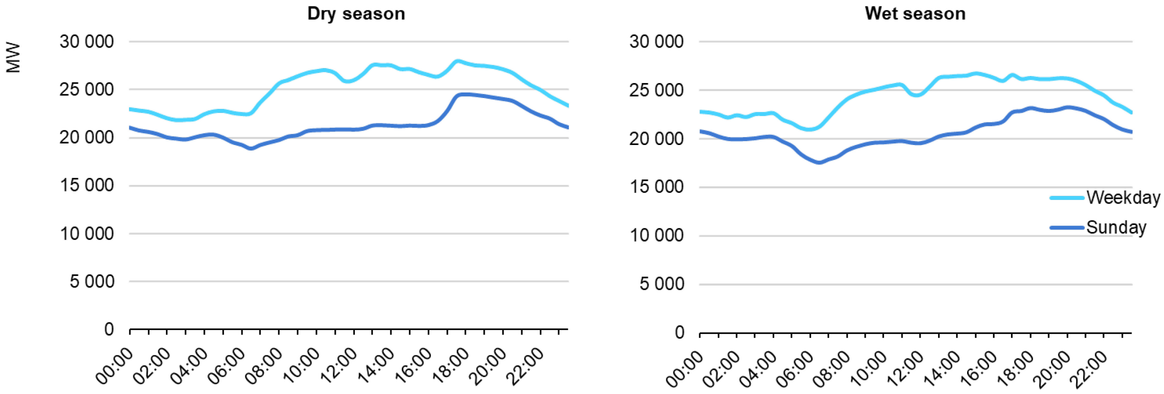
Contractual/institutional flexibility is the flexibility provided by underlying institutions in the power sector, including laws and general practices. It plays a key role in facilitating the optimal use of the technical flexibility resources. Most advanced economies have power markets to provide signals of the time and locational value of resources and to incentivise flexibility. For emerging economies with vertically-integrated structures, such as Indonesia, state-owned electric utilities are the single buyer, purchasing bulk power from private producers as well as their own subsidiaries under rigid contractual structures, which can often limit the use of technical flexibility resources.

In addition to technical and contractual flexibility, modern **system operational practices** provide another mechanism to foster the more flexible use of technical assets, particularly on the supply side, which help to address technical and economic concerns about a high share of VRE during the clean energy transition. Some of the key operational practices include real-time monitoring and dispatch, forecasting and system services. System planning practices could also be improved so that a long-term flexibility strategy is developed and implemented.

Understanding flexibility requirements, from short-term to long-term, can support the effective utilisation of, and levels of investment in, different flexibility resources and the services they provide. This flexibility is particularly important to accommodate high shares of VRE. The hour-to-hour variations in net demand (demand minus non-dispatchable VRE generation, a measure for the system flexibility requirements) of the system and the gap between minimum and peak net demand are robust indicators of the challenges and flexibility requirements on hourly and daily timescales, respectively. Currently the shares of VRE in both the Java-Bali and Sumatra systems are still less than 0.1%. Therefore, the profiles of net demand are nearly identical to the respective load profiles.

In the Java-Bali system, the daily demand patterns are influenced by the residential, business and industrial sectors. A typical weekday consists of morning, afternoon and evening peaks with the minimum demand in the early morning. On Sundays and public holidays, the majority of the demand is from the residential activities and the demand profile is relatively stable throughout the day with the daily peak occurring in the evening. The demand patterns are slightly different between the dry season (April to October) and wet season (November to March). In the wet season, there is a greater variability in the demand patterns in terms of higher ramp rates and a larger gap between daily minimum and peak demand.

Typical demand profile in the Java-Bali system on weekdays and Sundays, dry (left) and wet (right) season, 2019

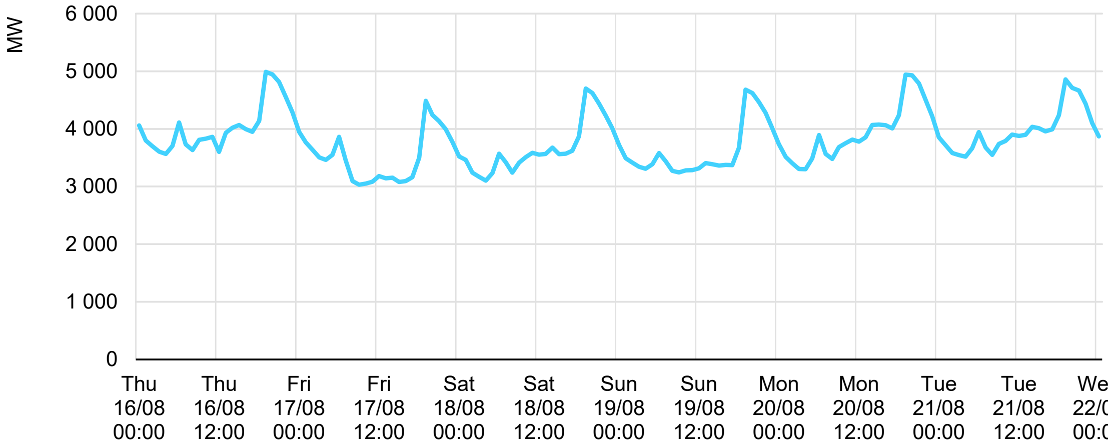


Source: IEA analysis of PLN Data.

The highest 1-hour upward ramp in the Java-Bali system occurs on weekday evenings at 2 615 MW (equivalent to 44 MW/minute) or 12% of the daily peak demand. The highest 3-hour upward ramp occurs on weekday mornings from around 07:00 to 10:00 which is 3 739 MW (equivalent to 21 MW/minute) or 15% of the daily peak demand. Given the size of the Java-Bali system, these ramping requirements are relatively small.

In Sumatra, the typical daily demand patterns for both weekdays and Sundays are similar since the residential sector represents the majority of overall demand at around 60%. The demand is relatively stable during the day with a sharp rise in the evening peak at around 6-7 pm. The highest hourly ramp is 1 040 MW, which is equivalent to 22% of the daily peak demand, while the 3-hour upward ramp is 1 440 MW or around 30% of the daily peak demand. Although such ramping requirements are more challenging than those in the Java-Bali system, they are still manageable given the reasonable share of hydropower and gas-fired generators in Sumatra, which are considered relatively flexible. In other systems, such as those in California and India, 3-hour ramps can be as high as 60-70% of the daily peak demand.

Demand profile during periods with high ramping requirements in the Sumatra system, 2018



Note: The maximum hourly ramping requirement in the Sumatra system occurred on Sunday 19 August from 17.00-18.00, while the maximum 3-hour ramping requirement occurred on Friday 17 August from 15.00-18.00.
Source: IEA Analysis from PLN Data.

Typical ramping requirements in Java-Bali and Sumatra systems

	Java- Bali system				Sumatra			
	2019		2025		2019		2025	
	1-hour	3-hour	1-hour	3-hour	1-hour	3-hour	1-hour	3-hour
Max ramp up (MW)	2 615	3 739	3 520	4 300	1 096	1 476	1 564	2 065
% of daily peak	12%	15%	13%	16%	22%	31%	19%	29%
Season	Wet	Wet	Dry	Wet	Dry	Dry	Dry	Dry
Period	Weekday evening	Weekday morning	Weekend evening	Weekend evening	Weekend evening	Weekend evening	Weekday evening	Weekend evening
Max ramp down (MW)	3 212	4 460	7 107	9 319	1 042	1 568	1 280	2 194
% of daily peak	17%	23%	35%	46%	22%	31%	17%	29%
Season	Dry	Wet-Dry Transition	Dry	Dry	Wet	Dry	Dry	Dry
Period	Weekend evening	Weekday evening	Weekend evening	Weekend evening	Weekend evening	Weekday evening	Weekday evening	Weekday evening

Note: Analysis is based on demand data from four representative days, the daily peak load in Java-Bali in 2019 and a full year of hourly demand data for Sumatra in 2018, projected to years 2019 and 2025. The dry season is April to October. The wet season spans November to March.

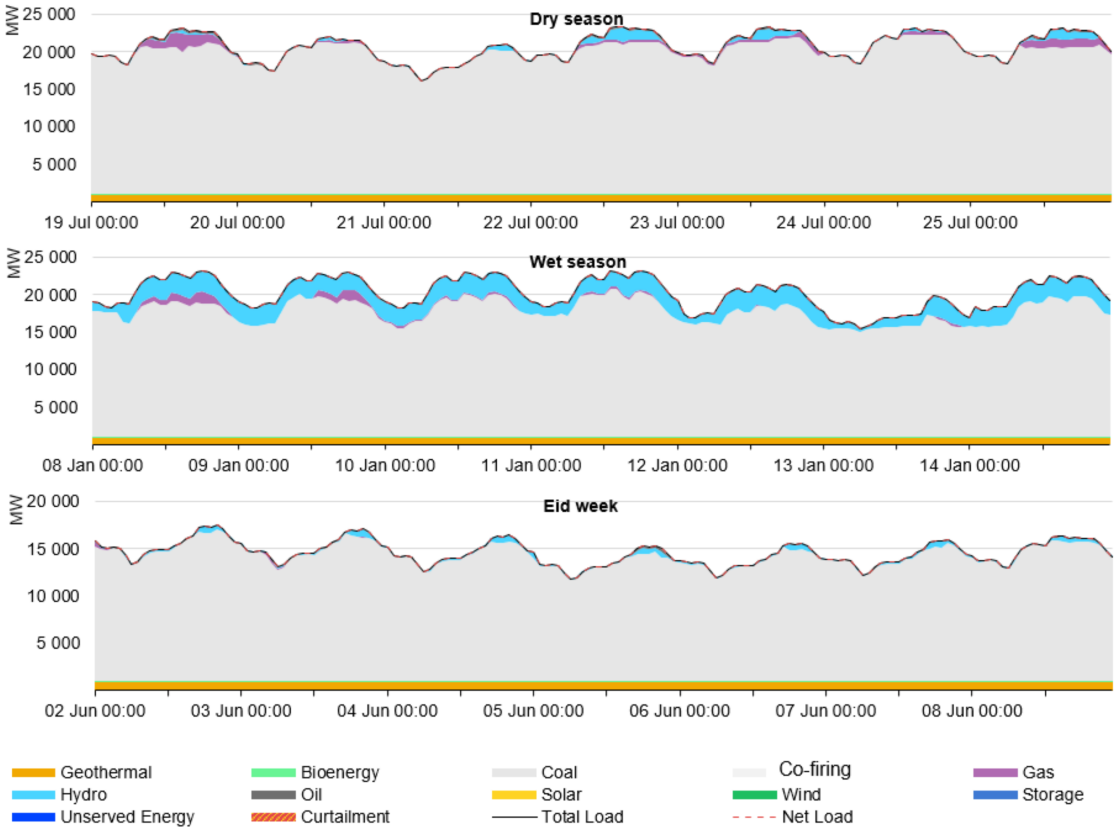
The gap between daily minimum and peak demand in the Sumatra system is in the range of 1 000 – 2 100 MW in 2019, which can be as high as 40% daily peak. In 2025, the gap is expected to increase to 1 500 – 3 000 MW or 38% of the daily peak. The larger the gap between minimum and peak demand, the greater the flexibility requirements and operational challenges for the system, which typically translate into frequent starts/stops of power plants.

With the smaller system size and the demand patterns, it appears to be more challenging to meet the flexibility needs of Sumatra compared to Java-Bali from the system operations perspective. Hence integrating VRE, particularly solar PV, into the Sumatra system would require greater flexibility resources. This is explored in detail in Chapter 3 where we discuss the scenarios with high solar PV in 2025. The planned interconnection between the two systems (at the earliest by 2028) will contribute to smoothing out variability and reducing the ramp rates of the combined system.

Dispatchable power plants, both fossil-fuel and hydropower, have been the primary flexibility resources in many power systems around the world, including Indonesia. They are operated subject to their technical capability, which typically includes the minimum stable level at which a specific generator can operate, the rate at which power output can be adjusted (the ramp rate), the start-up and shutdown times, and the constraints on how often a generator can be cycled (minimum up/down times as well as number of start-ups). Dispatchable power plants will be required to vary their generation outputs more significantly due the growing share of VRE and the associated variability and uncertainty of net demand as a result.

In Indonesia, power plants are still dispatched based on a merit order established according to the traditional categorisation of baseload, intermediate and peak. This categorisation is not only subject to technical characteristics, but also contractual constraints (more information provided in the next section). Geothermal and coal-fired plants operate as baseload leading to relatively stable outputs throughout the day. Gas-fired power plants are dispatched to accommodate changes in the demand throughout the day, similar to hydropower plants, subject to water inflow patterns. In addition, gas-fired generation also makes up the main difference in generation between the wet and dry season when hydro availability is low.

Typical weekly generation profiles by technology in the Java-Bali system in the dry season, wet season and week of Eid (June), 2019



With the rising share of VRE in the power system, thermal power plants in Indonesia, which were originally designed to operate as baseload, are expected to operate more flexibly to accommodate the variability arising from VRE. A range of strategies can make existing conventional power plants more flexible. These can be categorised into two areas: changes to operational practices, including contractual structures, and investment in flexibility retrofits. From international experience, the operating characteristics of conventional power plants can be significantly improved after retrofitting. However, the coal-fired power plants in Indonesia are relatively young and have flexible characteristics.

Average operating characteristics of conventional generation technologies

Technology	Minimum operating levels (% of capacity)		Ramp rate (MW/minute)		Warm start time (hours)	
	Typical	Retrofit	Typical	Retrofit	Typical	Retrofit
Coal	37%	20%	21	60	6	2.6
CCGT	45%	30%	21	56	1.6	0.5
OCGT	35%	20%	29	60	0.7	0.3
Hydro	**15%**	**-**	**60**	**-**	**N/A**	**-**

Notes: CCGT = combined-cycle gas turbines; OCGT = open-cycle gas turbine.

Sources: IEA (2017), Energy Technology Perspectives 2017; NREL (2012), Power Plant Cycling Costs 2012; Gonzalez-Salazar et al. (2018), "Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables"; Siemens (2017), Flexibility of Coal and Gas Fired Power Plants; Agora Energiewende (2017), Flexibility in Thermal Power Plants.

Hybrid power plants, which combine two or more technologies, are an emerging trend in Southeast Asia, including Indonesia, Thailand and Viet Nam. The 145 MW Cirata hydro floating solar PV power plant in Java-Bali combines solar PV with a hydro plant. It is one of the largest floating solar PV systems in the world and has the potential to contribute to system flexibility from the technical perspective by balancing the variability from the PV cells, particularly during the rainy season. At the time of writing, this project is expected to be in operation by the end of 2022, and is viewed as a pilot for the development of hybrid floating solar PV plants in many other islands to meet the renewable targets.

Electricity grids are another main flexibility resource that enables different sources to be shared across the regions. For Indonesia, the existing transmission system is regarded as one of the barriers to flexibility, due to the archipelago and volcanic characteristics of the islands. In the Java-Bali system, which is the main system in Indonesia, the transmission grid has a radial structure (long, thin and low density) from east to west with the demand centres in the north and south of the island, separated by mountains and volcanoes in the centre. Reinforcements to existing grids as well as interconnections between islands and with neighbouring countries could deliver significant flexibility improvements. A study of the ASEAN Power Grid also demonstrated that achieving sustainable development goals requires developing both grids and renewables, lest the excess thermal capacity be exported and thereby increase the overall emissions in the region.

Contractual structures limit the flexibility of the young thermal fleet

In its role as single buyer in the Indonesian power system, PLN procures power from its own generation assets as well as IPPs and leased generation assets. IPPs enter into long-term PPAs with PLN, providing them the budget security for project financing. As in other emerging economies, physical PPAs for thermal generation have historically been an effective tool to ensure investment in generation to meet the rapidly growing power demand in Indonesia. For the system, the cost of dispatching generators can be viewed as comprising two components: a capacity payment and an energy payment. If the capacity payment is large and the energy payment is low, as can be the case for coal-fired generation in the absence of costs for environmental externalities, the majority of the generation is paid for up front, and consequently the system operator has an incentive to keep running the generation for which they have already paid the costs.

In physical PPAs, it is common practice to agree on a certain amount of generation (**minimum offtake obligation**) at a fixed price in order to secure the income of the generator. This legal agreement suits systems seeking a baseload from a thermal fleet. Unfortunately, the generator has no financial incentive to provide flexibility and supplement the infeed from VRE when the system needs it, which is an important feature to enable integration of higher shares of variable renewables. For thermal generation, the guaranteed take obligations are often relatively high, well above the technical capabilities (minimum stable levels) of the assets. The PPAs often also specify other operating parameters in ranges that restrict their flexibility: ramp rates and start-up time. This barrier for flexibility has also been observed in other countries like India and Thailand.

Given the relatively young thermal fleet in Indonesia, the physical PPAs can potentially limit the use of technical flexibility for many years to come. According to the RUPTL, the total capacity of coal-fired IPPs in the Java-Bali system is planned to grow from 10 GW in 2020 to 19 GW by 2025, while the peak load is expected to grow from 25 GW to around 30 GW by 2025. Based on a typical lifespan of 30 years for coal plants, only two units would retire before 2030 and 14 GW would still be in operation beyond 2040. PPAs are usually established for a duration covering the technical lifetime of the plant.

Fuel supply contracts can also be a cause of inflexibility. Many thermal plants enter into long-term contracts for fuel supply. These are especially prevalent with fuel suppliers that need revenue certainty to support investment in related infrastructure. A notable example of this is with gas suppliers, where gas pipelines, LNG terminals and storage are all capital intensive, long-term investments. In Indonesia, **ToP**[10] clauses in gas supply contracts are common[11]. This effectively means that the fuel can be considered a sunk cost, modifying the marginal cost of

[10] Take-or-pay [obligations] is the term most commonly used in the gas market, while guaranteed (off)take obligations are used in the power market. Both terms imply a financial commitment to either pay for gas or run generation physically at a power generator.

[11] Hakam, D. F., and Asekomeh, A. O. (2018). Gas Monetisation Intricacies: Evidence from Indonesia. *International Journal of Energy Economics and Policy, 8(2), 174–181.*
Retrieved from https://www.econjournals.com/index.php/ijeep/article/view/6005.

the plant, as it has to be paid for irrespective of generating power with the fuel or not. In practice, these plants may be dispatched ahead of low-cost renewable technologies until carbon pricing is introduced. From a system operator perspective, it may be a rational choice under these circumstances to curtail wind and solar to run coal in a system with minimum take obligations, due to the uncertainty in forecasting wind and solar and the imperative to maintain system stability. However, from an environmental perspective it would still be optimal to dispatch renewables ahead of the coal fleet.

Summary of the flexibility challenge in Indonesia

Increasing the share of VRE requires increasing the flexibility of Indonesia's power system, particularly in Java-Bali. The main flexibility challenges of most power systems, including in Indonesia, can be grouped into three main building blocks: technical, contractual/institutional and operational practices. Chapter 3 examines some of these challenges in greater detail in order to assess the impact they have on the ability of the systems of Java-Bali and Sumatra to accommodate higher VRE shares in 2025, and on the corresponding costs and emissions. Chapter 4 explores a few options to address some of these challenges.

Technical inflexibility

- **Inflexible thermal power plants:** As some generation technologies (coal, nuclear, geothermal) are more efficient at high capacity factors, their higher costs per unit of output may be a barrier to flexibility. As shown in Chapter 3, the thermal power plants in Java-Bali and Sumatra will be no obstacle in 2025 because the ramping requirements remain within the capability of the existing assets, without the need for retrofits.
- **Grid infrastructure:** The failure of the Ungaran-Pemalang transmission line in Central Java contributed to the August 2019 blackout that cost an estimated IDR 90 billion in damage. It demonstrated that the network has weak connections relative to the power demands. The RUPTL 2021, stated plans to create a new 500-kV Northern Java corridor that would run parallel along the existing lines in Banten, West Java, Central Java and East Java.
- **Geographical topology:** The shortest distance between the two coastal cities of western and eastern Java, Cilegon and Banyuwangi, is 960 km, or approximately the same distance between Washington DC and Chicago under the PJM system of Pennsylvania, New Jersey and Maryland. The general direction of electricity flows is from the east, where there is abundant coal and excess capacity, towards the higher demand regions in the west. Such a distance, combined with limited transfer capacities, can pose challenges in terms of voltage stability.

Contractual and institutional frameworks

- The **PPAs** in Indonesia often have clauses specifying minimum take obligations which are relatively high. This is one, or the main, source of system inflexibility in Indonesia because it forces PLN to prioritise power generation from these plants when optimising its dispatch. Such conditions make it uneconomical for PLN to make use of VRE with its lower operating costs. With increasing shares of VRE, there could be more VRE curtailment.
- **Fuel supply contracts** can indirectly limit the operational flexibility of power plants through minimum offtake and penalties, especially when the fuel suppliers require additional certainty in their investments. In Indonesia, ToP clauses, which are common in its gas supply contracts, also constrict PLN's ability to take advantage of the operational flexibility of gas-fired power plants.

System operational practices

- **Overly optimistic demand forecasts:** The excess capacity in the Java-Bali system and high reserve margin have been in part due to overly optimistic demand forecasts. These forecasts resulted in programmes such as the 10 000 MW Fast Track Programme 1 in 2006, the 17 918 MW Fast Track Programme 2 in 2010, and the 35 000 MW Fast Track Programme in 2014 where regulations and permits were simplified and financing was made available for both PLN and IPPs to build up new capacity rapidly. Lower than expected electricity demand resulted in the high observed reserve margins, forcing PLN's power plants to run at low capacity factors. Adding renewable capacity appears uneconomical unless some thermal capacity is retired or is allowed to run at even lower capacity factors.
- **Control systems and real-time monitoring:** There is still limited deployment of advanced monitoring infrastructure (AMI) and real-time control of generators, electricity networks and high-voltage substations. AMI deployment provides better insights into demand patterns, as well as more efficient operations and better modelling of the power system. The latter is important as the system operator can better assess the system performance, and plan and prepare for a wider array of scenarios. PLN is currently upgrading control rooms to include load frequency control and automatic generation control in the Java-Bali system to balance supply and demand.
- **Reserve margin and system services requirement:** Although the probabilistic technique of LOLP is used as the reliability criterion to determine the required reserve margin in Indonesia, the existing approach is still largely based on deterministic criteria. The high reserve margin criteria (35%), together with the optimistic demand forecast, has resulted in overcapacity.
- **Grid code**: Prior to the grid code revision of 2020, there were no explicit terms covering generation from VRE, nor specifications on fault ride-through, and low- and high-voltage ride-through. A distribution grid code is under preparation to bring further improvements.

Chapter 3. Energy transition pathways for Java-Bali and Sumatra in the short term

Key findings – Java-Bali and Sumatra power systems in 2025

- Delays in deploying new geothermal and hydro capacity, and in establishing a sustainable supply chain to support biomass co-firing in coal plants (which comes at a price premium) put the realisation of the target for a 23% share of renewables in electricity in 2025 at risk. This risk could be mitigated by deploying solar PV at a faster pace.
- To meet the 23% renewables target, the SolarPlus Scenario, in which 17.7 GW of solar PV in the combined systems of Java-Bali and Sumatra (against 2.8 GW in the RUPTL) are deployed to compensate for non-committed new capacities, a possible failure to deploy biomass co-firing appears to be viable from a system operation perspective. Flexibility requirements are higher compared to the Base Scenario (where the assets are consistent with the RUPTL), especially in the smaller Sumatra system, but remain within the capabilities of the existing and planned dispatchable assets.
- Compared to the Base Scenario, the SolarPlus Scenario leads (without taking into consideration carbon pricing) to 2% savings in operating costs per year (essentially through avoided fuel costs), which could be used to implement new flexibility measures in the future, and a 4.5% decrease in CO_2 emissions, at the expense of a 14% PV curtailment rate in Sumatra.
- The total costs of the SolarPlus Scenario are higher than the Base Scenario due to the higher investment cost for PV technology. Authorities can take various measures to bring down the cost of solar PV with a concrete plan to deploy PV.
- Given the abundant generation capacities, the Java-Bali and Sumatra systems can accommodate the electrification of cooking and road transport to meet the ambitious national targets. Even though most of the additional demand in Java-Bali is fulfilled by the thermal fleet, the cross-sectoral emissions are reduced by 1% with all new loads electrified, while solar curtailment is reduced by 6%.
- The main barrier to higher gains from solar PV is the inflexibility in the PPAs with coal IPPs which cover a significant share of the demand. Removing contractual inflexibilities would more than double the emissions savings from

the SolarPlus Scenario (relative to the Base Scenario) and reduce solar PV curtailment to negligible rates.

- Given the over-built thermal capacity in the system, adding new generation capacities to the system leads to stranded assets. This study does not examine the financial implications of the excess capacity. It only illustrates the limited room for renewables in the Java-Bali and Sumatra systems in 2025. In the absence of a coal phase-out programme, and despite the expected economic growth, the efficiency of any new generation project will be affected.

This chapter provides a detailed techno-economic assessment of the capability of the current Java-Bali and Sumatra systems to integrate the target of a 23% share of renewables in the electricity mix by 2025, notably with solar PV. Thanks to its potential speed of deployment, solar PV technology was identified as a robust choice to fill the gap between the actual deployment track of renewable generation and the 2025 target. Wind power is kept at the levels planned in the RUPTL.

For the purpose of illustrating system performance, this study looks at capacities of solar PV which are six times higher than the current plans (17.7 GW instead of 2.8 GW), as a high-end estimate of how much solar PV capacity would be useful to fulfil the target, regardless of how realistic the deployment pace would be to reach these levels. In order to assess the ability of these systems to handle the challenges relating to an increase in VRE deployment, in the short term the impact of the transition to VRE was analysed from the perspectives of the three key sustainability pillars of the Indonesian energy transition policy, namely, *Availability* (security of supply); *Affordability* (least cost) and *Acceptability* (environmental sustainability).

The metrics used to quantify the system benefits and value of flexibility options are: reductions in the cost of fuel, operation and maintenance (O&M), and carbon dioxide (CO_2) emissions. Other metrics include the level of VRE curtailment, contribution of different sources to system adequacy and system services including system inertia and ramping requirements.

Modelling of the Java-Bali and Sumatra systems

To better understand the flexibility requirements of the Java-Bali and Sumatra systems as Indonesia transitions towards higher shares of VRE, a production cost model[12] of the two power systems was developed. Key inputs were forecasted demand profiles, the techno-economic characteristics of the power plants, hydropower energy constraints, transmission network constraints and VRE generation profiles.

The modelling of the power systems in Java-Bali and Sumatra is predominantly based on data requested and received from Indonesian stakeholders (the MEMR and PLN) with key information on the different components of the power system. In the absence of specific data for either Indonesia or a specific component of the power system, either public domain information or assumptions based on best-practice were made to allow for completeness of the model.

The study is based on the planned systems in Java-Bali and Sumatra in 2025 as per the latest Electricity Business Plan (RUPTL 2021) that aims to achieve the national renewable target of a 23% share of renewables in the electricity mix by 2025.[13] Therefore, the supply and demand outlook as per the RUPTL in 2025 form the basis of the model and the Reference or **Base Scenario** apart from one notable exception: the share of biomass in the electricity mix in the Base Scenario is 2.2% (against 3.5% in the RUPTL) although the installed capacities are the same. With a level of bioenergy contribution as in the RUPTL, the 23% target would not be achieved. Since co-firing takes place in PLN's coal plants at the blending ratio of 10%, reaching the RUPTL bioenergy share requires a yearly capacity factor of those plants (with a capacity of around 12 GW) around 80%, leading to an even greater share of coal-fired power and higher fuel costs. In contrast, the Base Scenario assumes economic dispatch of the thermal fleet with the contractual constraints described below.

The model was developed with an hourly temporal resolution, using projected demand profiles based on demand forecasts for both annual energy and peak demand from the RUPTL 2021, with load shapes based on historical profiles.[14] In addition, the model captures the techno-economic characteristics of both existing and planned power plants, fuel supply (including hydropower) constraints, transmission and VRE production profiles. While the model is deterministic, operating reserve requirements are captured based on load risk and renewable forecast errors to ensure sufficient capacity is reserved for both balancing and spinning reserves. In addition, constraints in PPAs with coal IPPs and ToP contracts for the supply of gas are implemented using assumptions derived from

[12] A production cost model simulates detailed operation of a given power system by co-optimising hourly (or sub-hourly) dispatch and procurement of reserves.

[13] The 23% share of NRE is at the country level. Different island-power systems are expected to have different contributions to achieving this NRE target. In the RUPTL's Low Carbon Scenario, Sumatra's NRE share is 43.6% while that of Java-Bali is 17.1%. Given that the combined systems represent 80% of the country's demand for electricity, the study aims to fulfil the 23% target by covering Java-Bali and Sumatra together.

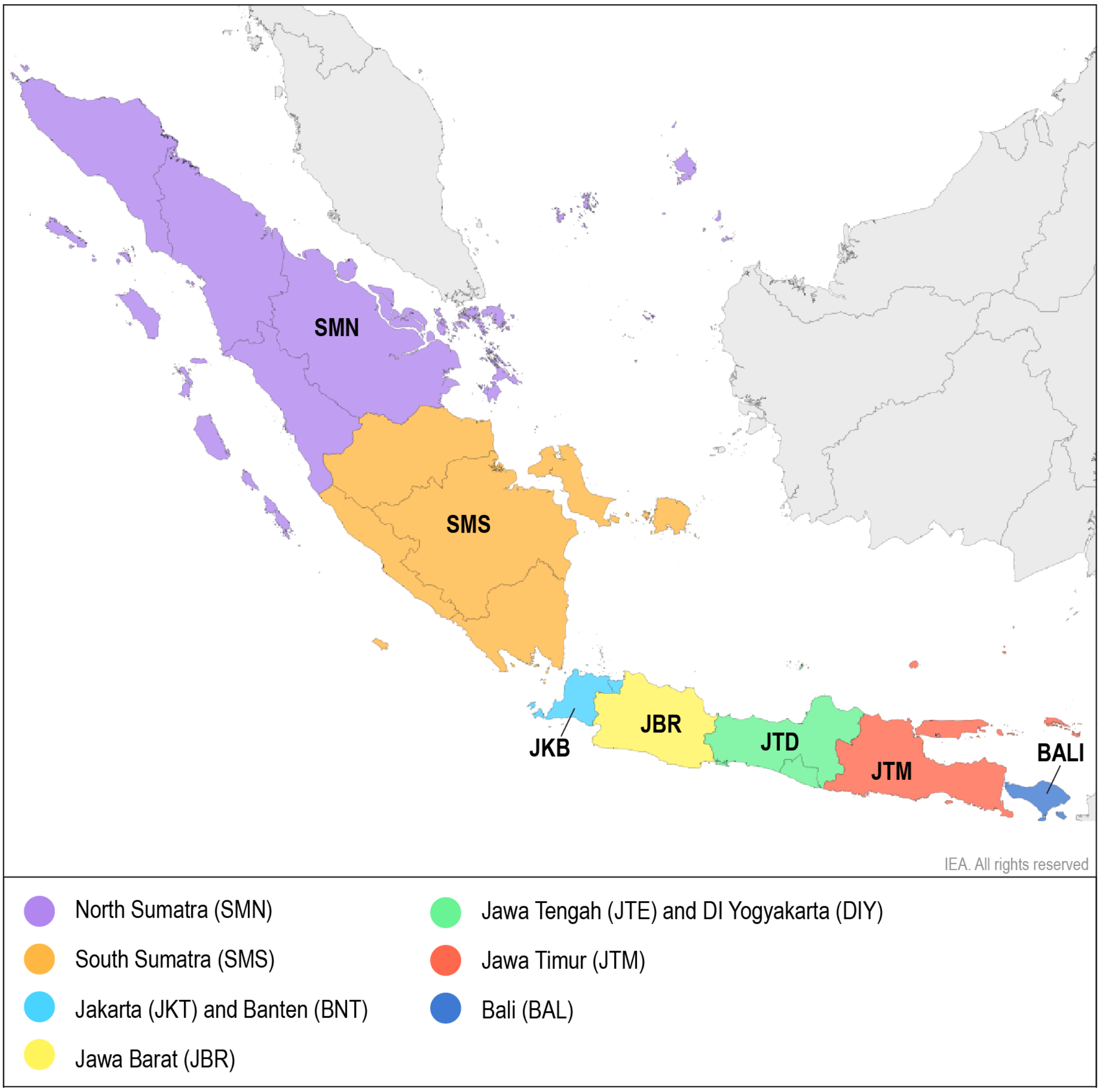
[14] Historical profiles for the Java-Bali system are based on the demand for four representative days from 2019, up-scaled using the daily energy profile across the entire year (365 days). Meanwhile the historical profile for the Sumatra system included a full hourly profile (8 760 hours) for 2018.

historical (2019) data. The annual minimum offtake for coal IPPs (set to 60%)[15] was based on the range of capacity factors of IPPs in 2019 in both Java-Bali and Sumatra while allowing the simulation outcomes for the Base Scenario in 2025 to meet the renewables target. Gas contracts are assumed to include daily ToP obligations at the regional level scaled up from the 2019 consumption according to the capacity growth of gas-fired plants.

The Java-Bali and Sumatra systems are disaggregated into five and two regions, respectively. For the Java-Bali system, the modelling regions are in accordance with the control regions of PLN, while for the Sumatra system, two regions are assumed: North (SMN) and South (SMS), based on the provinces and the location of the key bottleneck in the north-south 275 kV transmission corridor between Jambi and Sumetara Barat provinces. The high-level transmission network topologies (150 kV, 275 kV and 500 kV) connecting different operating regions are modelled. In 2025, the Sumatra and Java-Bali systems will still not be interconnected and will therefore be operated independently of one another.

[15] Experience from neighbouring countries supports values above 60%. Such capacity factors, however, would not allow meeting the 25% targets in 2025 unless unrealistic assumptions about the capabilities of other types of units in the system were made. No capacity factor constraint is added to the plants owned by PLN and its subsidiaries.

Representation of the Java-Bali and Sumatra power systems



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA Analysis of PLN (2021), RUPTL 2021.

Alternative pathways towards 2025 and their impacts on the sustainability targets

In addition to the Base Scenario in 2025, the analysis considers additional scenarios that explore different pathways for Indonesia to meets its renewables target in 2025. The additional scenarios revolve around the following main sensitivities:

- Renewables mix, based on both the status and lead-time of renewable technologies in the RUTPL and ensuring that Indonesia meets its renewable targets for 2025
- Additional demand due to electrification of new end-uses (clean cooking and electric vehicles)
- Contractual constraints on thermal plants which limit their flexibility.

Three scenarios look at various mixes of renewable sources around the Base Scenario. Two of them focus on the role of biomass co-firing: how the system performance and renewable targets are affected by either the imperative of meeting the electricity share of biomass in the RUPTL (**Enforced Co-firing Scenario**) or if the biofuel supply chain was not in place (**No Co-firing Scenario**).

The central scenario of the study is the **SolarPlus Scenario**, the purpose of which is to provide a sense of the potential value and impact of solar PV in the power systems compared to the other renewable and non-renewable technologies for which there are planned but uncommitted capacities in the RUPTL 2021. Due to the long construction times of hydro and geothermal, and the uncertainty around deploying the biofuel supply chain logistics for biomass co-firing, solar PV is identified as a technology with high potential to ensure Indonesia meets the renewable targets for 2025. This is especially so under the right enabling conditions, which can allow for relatively short leadtimes for its deployment.

Alternative scenarios (**electrification scenarios**) then consider the potential to include targets for electrification of end-uses (clean cooking, electric vehicles) which, up until now, have not formed part of the RUPTL despite being on the government agenda, and their impact on CO_2 emissions, in particular. Indeed, the government strategy aims at reducing the use of oil products in final energy consumption through electrification of cooking (to replace traditional biomass and LPG) and road transport.

Finally, another set of scenarios (**scenarios with contractual flexibility**) consider the impact of removing the assumed contractual constraints in PPAs and on gas supply contracts.

Scenario settings in 2025

Scenario	Electricity mix	Storage and EVs	Demand	Share of RE (VRE) Sumatra and Java-Bali
2025 Enforced co-firing	RUPTL	RUPTL	RUPTL	23% RE (1.9% VRE)
2025 Base	RUPTL (with economic dispatch of co-firing)	RUPTL	RUPTL	22% RE (1.9% VRE)
2025 Without co-firing	No Co-firing	RUPTL	RUPTL	20% RE (1.9% VRE)
2025 SolarPlus	No co-firing High share of solar PV	RUPTL	RUPTL	25% RE (10% VRE)
2025 SolarPlus + Clean cooking	No co-firing High share of solar PV	RUPTL	Clean cooking	25% RE (10% VRE)
2025 SolarPlus + EVs	No co-firing High share of solar PV	EVs	RUPTL	25% RE (10% VRE)
2025 SolarPlus + Clean cooking + EVs	No co-firing High share of solar PV	EVs	Clean cooking	25% RE (10% VRE)
2025 SolarPlus With contractual flexibility	No co-firing High share of solar PV Thermal plants contractual flexibility	RUPTL	RUPTL	28% RE (10% VRE)

Enforced co-firing: This scenario is the most compliant with the plans in the RUPTL. The coal-fired plants where biomass co-firing takes place (owned by PLN, with a capacity of 12 GW) are forced to run at least 80% of the time to equal the bioenergy share in final energy in the RUPTL.

Without co-firing: This scenario assumes that biomass co-firing is not yet possible in 2025 due to either fuel supply logistics, or other technical reasons that would prevent the designated coal-fired capacity to co-fire the expected 10% biomass in coal plants for generation purposes. In this scenario, the capacity assigned to co-firing in the RUPTL 2021 is therefore maintained as normal coal capacity and those plants are not forced to run to meet a given capacity factor.

SolarPlus: This scenario assumes that all non-committed generation capacity from the RUPTL 2021 (according to the unfulfilled government quota) for deployment up until 2025 is replaced with utility-scale solar PV generation of approximately the same energy output. Similar to the No Co-firing Scenario, biomass co-firing is maintained as coal capacity. In addition, most of the non-committed generators are geothermal and hydropower plants, and hence are regarded as a large uncertainty in Indonesia's ability to meet its national renewable target of 23% by 2025 due to long lead times. This scenario therefore leads to a solar PV capacity of 18 GW[16] for the combined systems of Java-Bali and Sumatra.

[16] Hourly solar generation profiles are simulated from selected sites in Sumatra and Java-Bali based on resource potential distance to the grid and distance to demand centres. No rooftop solar is considered.

The next three scenarios are variants of the SolarPlus Scenario and have the same generation capacity. The demand is increased in comparison to the RUPTL Base Scenario, which does not include these new end-uses of electricity despite being part of the government strategy. The SolarPlus Scenario and the electrification variants all entail a very optimistic deployment pace for new assets (solar PV and new electric uses), but these scenarios are illustrative of the impact of these technologies on the system.

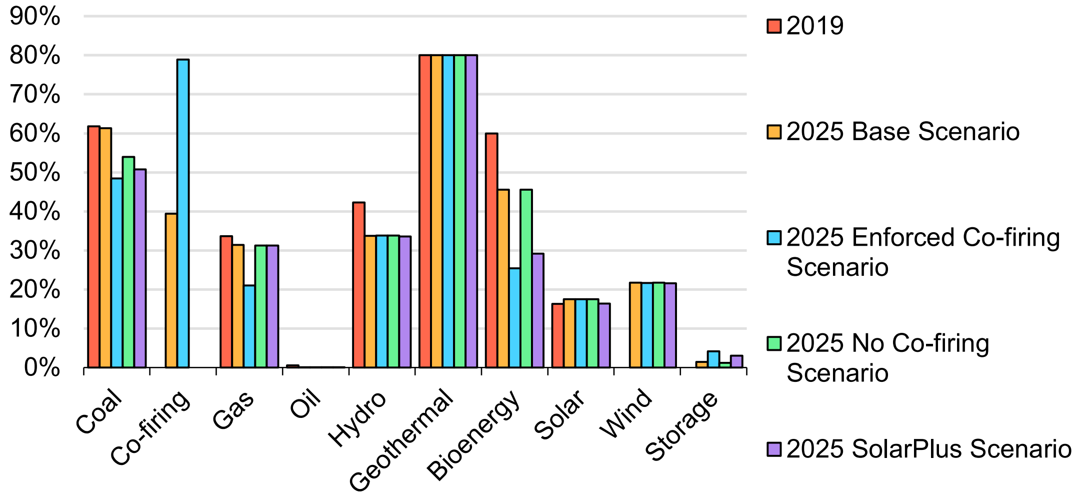
(Electric) clean cooking in Indonesia will be scaled up substantially as there is a nationwide programme to promote electric cooking to reduce dependency on traditional biomass and imported LPG. The increase in electric cooking will have an impact on the power system with the increase in both total and peak demand of electricity. In this case, we modelled demand profiles for electric cooking in various regions in Sumatra and Java-Bali according to IEA's Sustainable Development Scenario (approximately 20% of households).

Electric vehicles (EVs) will have a major role to play in clean energy transitions across Indonesia. There are policies to support the development and adoption of EVs, including the national EV roadmap with an ambitious target for 2050. By 2025, more than 370 000 electric 4-wheelers and 11.8 million electric 2-wheelers are targeted to be on the roads of Indonesia. The uptake of EVs will have implications for the power sector with the rise in both total and peak demand. At the same time, EV charging represents an opportunity to accommodate a higher share of solar PV, especially if managed charging is considered, which is not the case here.

We also consider a scenario that combines the electrification of both end-uses (**clean cooking + EVs**).

Finally, we explored a variant of the SolarPlus Scenario where the contractual constraints of thermal power plants are relaxed (**Contractual Flexibility Scenario**). In all the previous scenarios, assumptions were made about the extent of the inflexibility in contracts. In particular, the minimum capacity factor of IPPs was set to a level (60%) which was compatible with reaching the 23% target in the Base Scenario, and gas units were constrained by a contract requiring a daily take of gas at the regional level matching the volumes of the RUPTL. In this scenario, the annual capacity factor of IPPs is allowed to be lower than 60% and gas supply constraints are set to annual levels instead of daily.

Impact of the scenarios on plant capacity factors



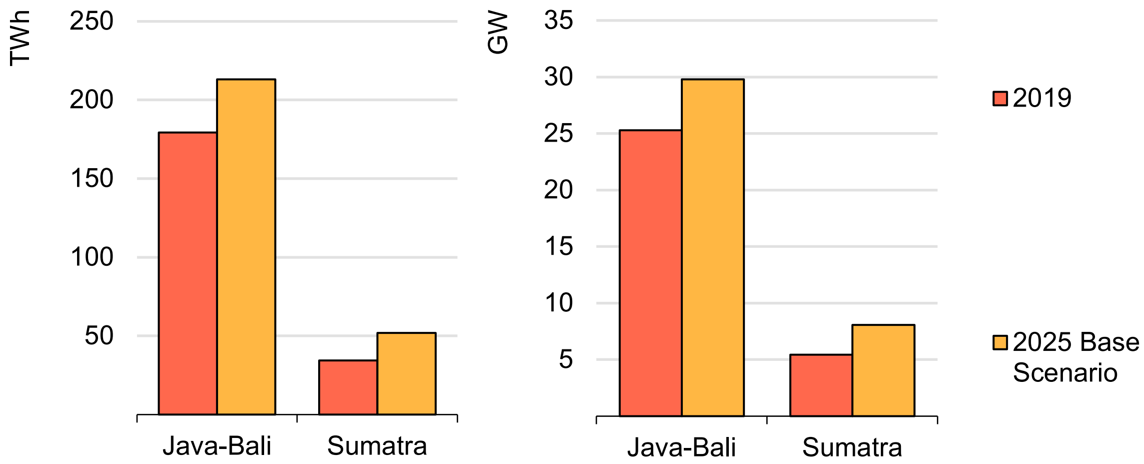
The potential of solar PV to provide a low-risk pathway to achieve the 2025 renewable targets

Between 2019 and 2025, the RUPTL 2021 expects the annual electricity demand to grow by 19% in the Java-Bali system and by 52% in the Sumatra system, while peak electricity demand would increase by 18% (4.9 GW) and 49% (2.6 GW) in Java-Bali and Sumatra, respectively. In order to both achieve the renewable targets and meet growing electricity demand, the RUPTL details the necessary capacity additions between 2021 and 2025, and calls for certain coal plants to begin co-firing biomass at the ratio of 10%.

In the Java-Bali system, capacity additions according to the RUPTL 2021 are still focused on coal, but with notable shares of gas as part of its plan to increase flexibility. Solar and wind capacity additions are also expected but will contribute only a small part of the system in the next decade. In terms of generation capacity, renewable energy represents around 25% of the total capacity (excluding co-firing), of which wind and solar PV represent about 5%.

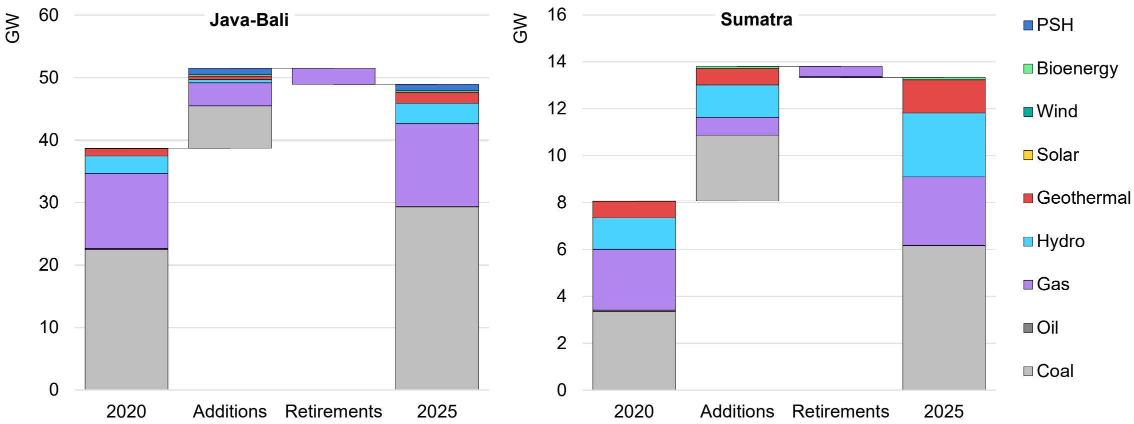
The Enforced Co-firing Scenario is established according to these projections, with approximately 23% of generation coming from RE, of which 2% comes from VRE. The Reference (Base) Scenario has the same capacities but does not force co-firing plants online, falling short of the 23% target.

Annual demand (left) and peak (right) in the Java-Bali and Sumatra systems in 2019 and 2025 according to the RUPTL



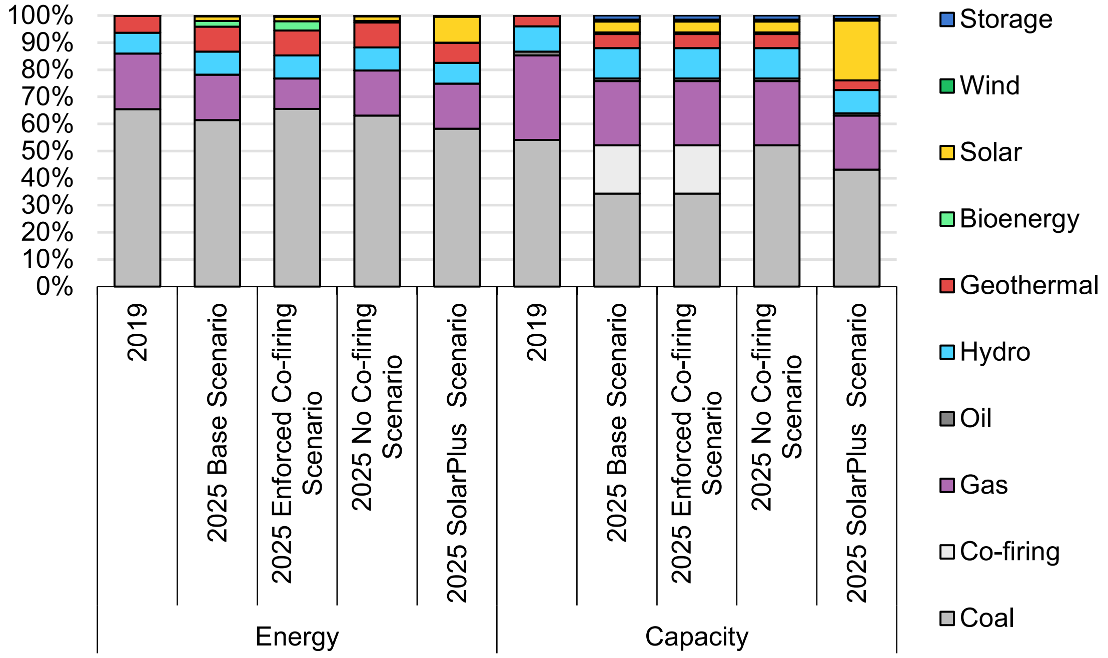
Source: PLN (2021), RUPTL 2021.

Capacity additions in the Java-Bali and Sumatra systems according to the RUPTL



Notes: Biomass co-firing is included in the coal capacity (in existing plants). PSH = pumped storage hydro.
Source: IEA analysis of PLN (2021), RUPTL 2021.

Capacity mix and the share of annual generation for the different modelling scenarios in 2019 and 2025



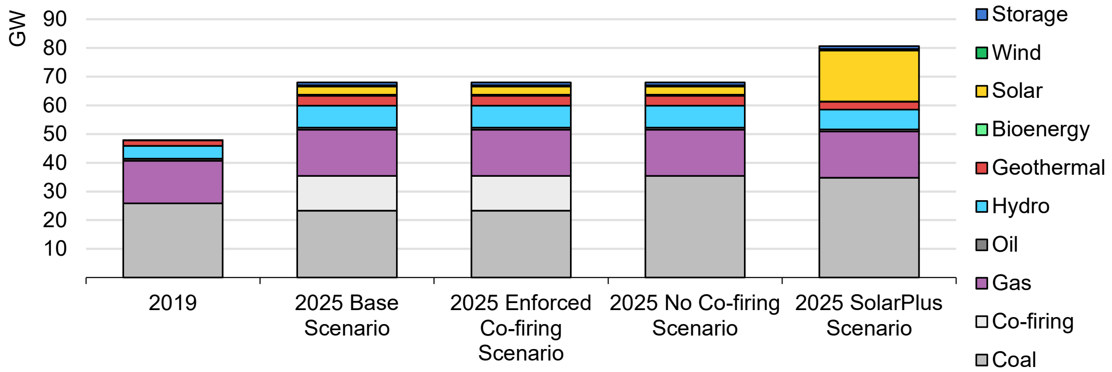
Note: The energy contribution of the biomass co-firing capacity is split into its different fuel components of coal and bioenergy. PSH = pumped storage hydro.
Source: IEA analysis of PLN (2021), RUPTL 2021.

The main assumption regarding the share of renewables in the SolarPlus Scenarios is that the 23% RE target in 2025 is achieved in the combined systems of Sumatra and Java-Bali.

Total installed capacity in the SolarPlus Scenario (and variants) is 81 GW for the Java-Bali and Sumatra systems, which is higher than the 68 GW capacity in the Base Scenario as a result of the lower capacity factor (CF) of solar PV plants (~18%) relative to both geothermal (80%) and hydropower (~40%) plants in the modelled system. The total VRE capacity in the SolarPlus Scenario is therefore 18 GW across both Java-Bali and Sumatra, compared to just 3 GW in the Base Scenario.

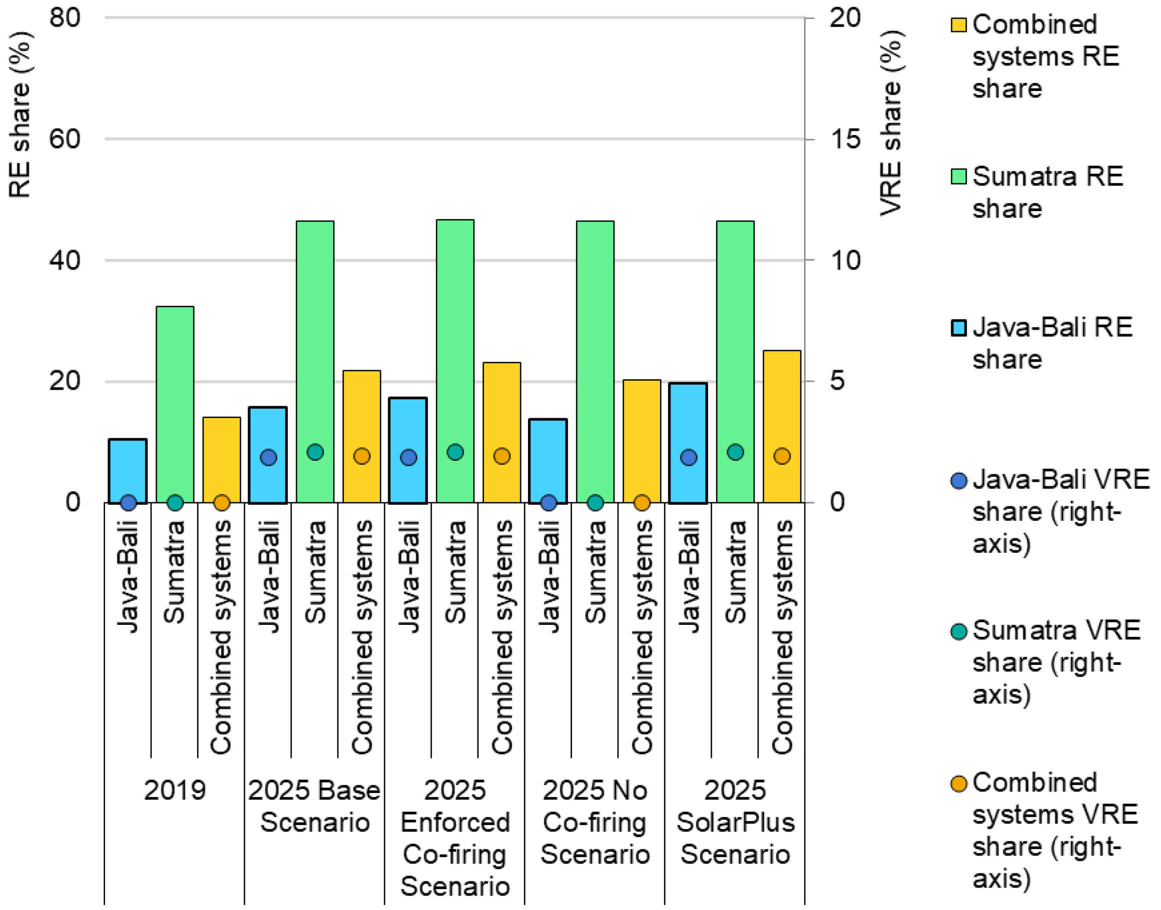
The overall share of VRE is around 10% (15% in Sumatra and 9% in Java-Bali).

Installed capacity of each generation technology across the different modelling scenarios in 2019 and 2025 in the Java-Bali and Sumatra systems



Note: PSH = pumped storage hydro.
Source: IEA analysis of PLN (2021), RUPTL 2021.

Share of renewables and variable renewables (VRE) in electricity production, 2019 and 2025 scenarios



Source: IEA analysis of PLN (2021), RUPTL 2021.

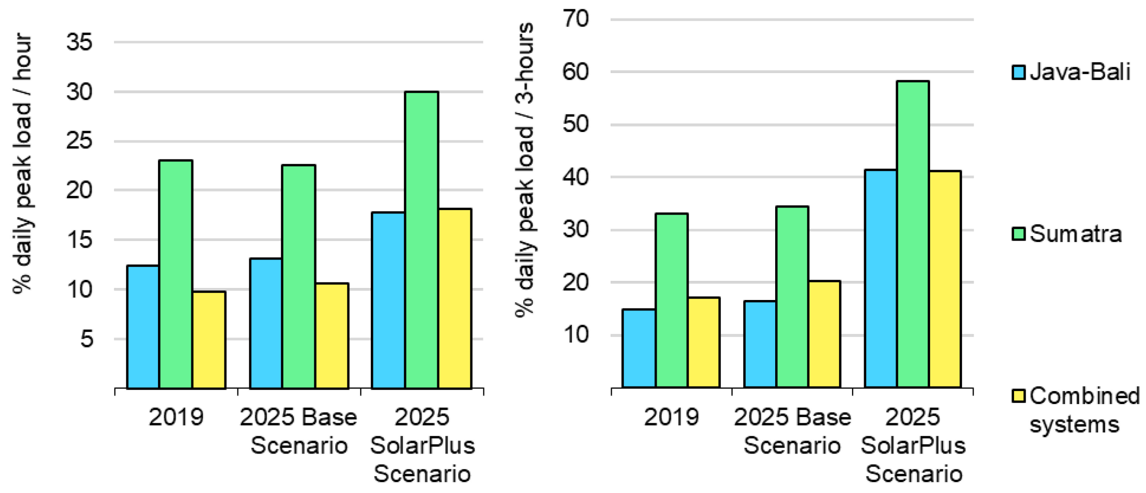
Flexibility requirements increase with higher shares of VRE

As the share of VRE in the Indonesian power system increases, there will be an increase in the need for flexibility to operate the system, driven by the specific characteristics of VRE resources. For example, the variability in supply due to changing weather conditions across multiple timescales (for example, daily, weekly or seasonal) will begin to drive the operation of the power system. Examples of this could be in the way that dispatchable generation is operated, or the way that power flows across the grid.

Several indicators can demonstrate the growing need for flexibility in a system. One way in which increased VRE deployment, and more specifically solar PV, affects power system operation is through increased daily cycling of dispatchable generation in order to accommodate the solar production and the greater swings in net demand. The technical constraints of generators may limit the flexibility of certain generators, due to aspects such as minimum generation levels for stable operation, constraints in the cycling of units (for example, minimum up or down times), start-up times and ramp rates.

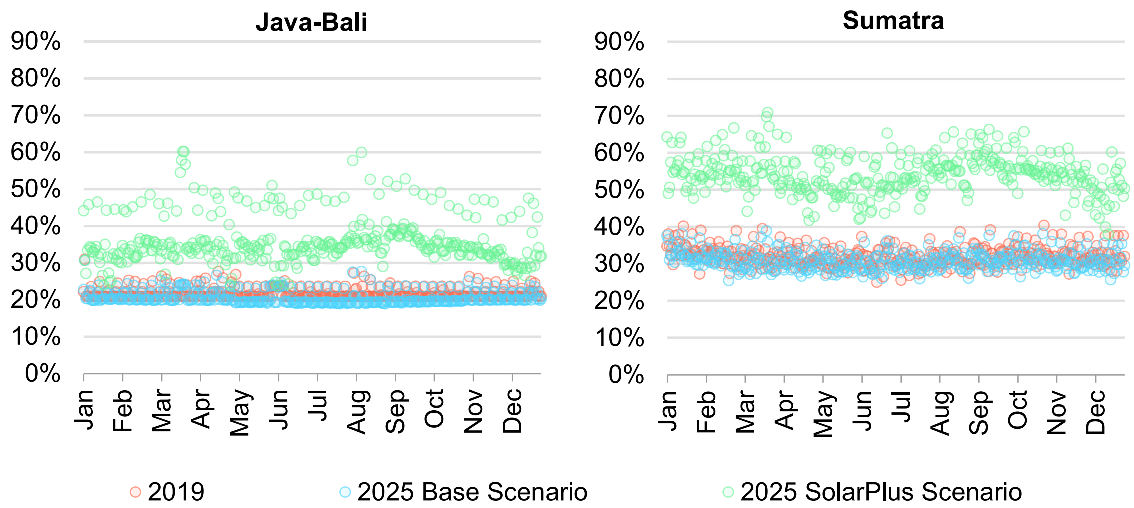
One of the implications of larger shares of solar PV is that systems begin to experience higher **ramping requirements**, both in terms of instantaneous ramp rates as well as over more prolonged periods such as 3-hour ramps. In 2019, with negligible deployment of VRE capacity, ramping requirements were driven solely by variations in demand. However, by 2025 ramp rates increase for all scenarios. Notably, the **Java-Bali and Sumatra systems both have sufficient flexibility to handle these ramp rates** through planned and existing dispatchable capacity.

Change in the ramping requirements under different scenarios in 2019 and 2025



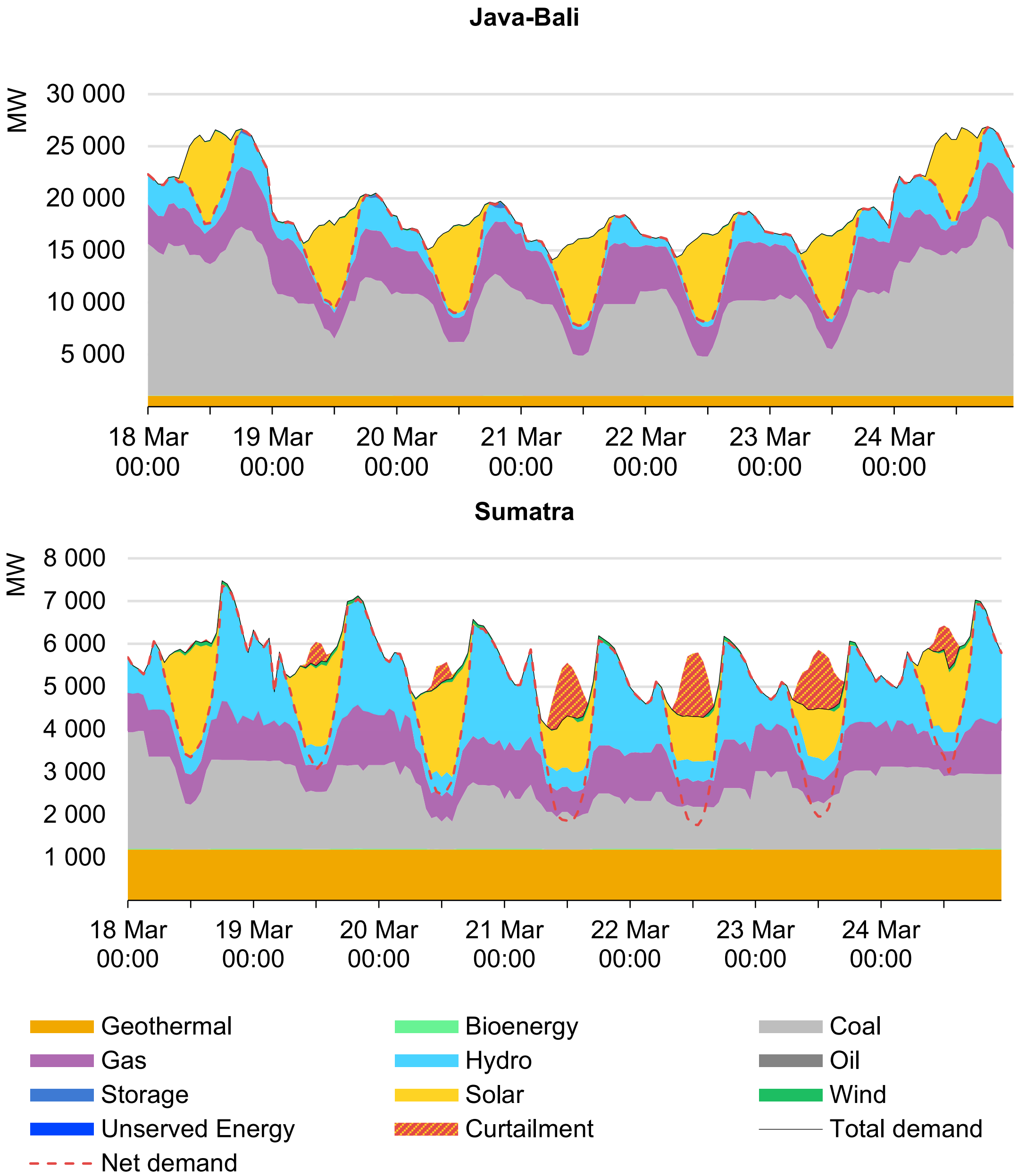
Another indicator of flexibility requirements is the **gap between daily minimum and peak net demand**, which is indicative of the swings in net demand, and which widens with the deployment of more VRE. This gap between daily minimum and peak net demand drives the operation of dispatchable generation and leads to more frequent start-ups, shutdowns and the cycling of generators in order to accommodate the intra-daily variability in the supply-demand balance. In 2019, this gap is driven primarily by daily variability in demand, and is 20-31% in the Java-Bali system and 25-40% in the Sumatra system. In 2025 (Base Scenario), this daily gap increases in absolute terms but so does the peak demand. Therefore, this gap actually remains almost in the same range in both the Java-Bali (19-31%) and Sumatra (26-39%) systems. However, with an accelerated deployment of solar PV (SolarPlus Scenario), this daily gap grows significantly in both the Java-Bali (24-60% of daily peak demand) and Sumatra (38-71% of daily peak demand) systems.

Evolution of the daily gap between minimum and peak net demand as a percentage of peak net demand in the Java-Bali and Sumatra systems



While these larger swings in net demand do pose a challenge to these systems, both have sufficient flexibility in 2025 to accommodate these changes. The Sumatra system will experience greater variability than the Java-Bali system due to its demand shape, its higher share of VRE (15%) in the system and its smaller system size. However, the model shows that Sumatra would be able to accommodate these higher shares of solar PV due to the inherent flexibility of its thermal and hydro fleet, with no negative impact on the system reliability (no unserved energy) and at the expense of solar PV curtailment (14.5% annually in Sumatra, equivalent to 3.4% over both the Java-Bali and Sumatra systems combined) occurring in periods of both low demand and peak solar production around midday. Curtailment takes place when demand drops below the minimum generation levels, which are defined by the system needs (reserves and flexibility needs) and technical and contractual constraints of the thermal fleet. Curtailment could be reduced at the cost of spilling hydro resources from run-of-river plants.[17]

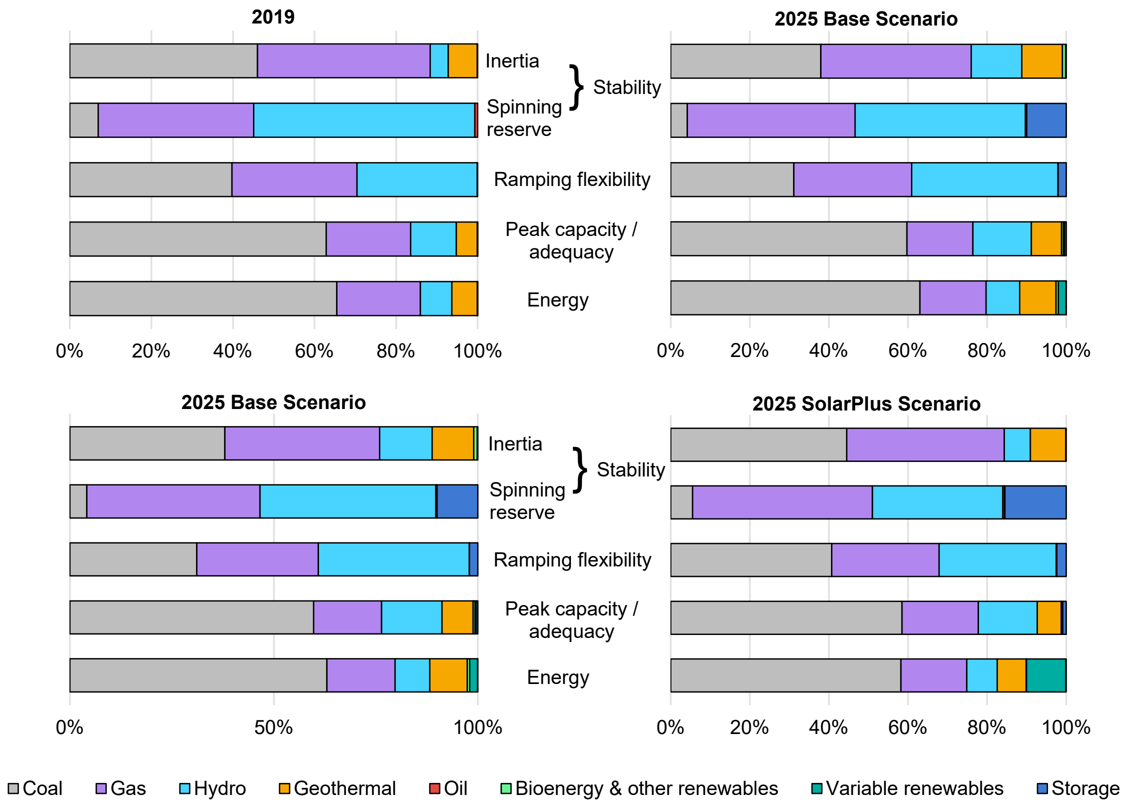
Generation profiles by fuel type during the period of minimum net demand in the SolarPlus Scenario for the Java-Bali and Sumatra systems, in 2025



[17] In our model, run-of-river plants are assumed to have priority over solar PV. This assumption is true if there are contractual agreements between plant operators and PLN with ToP clauses.

The Java-Bali system has 9% VRE penetration in the SolarPlus Scenario, and can reliably integrate VRE due to both the larger size of the system and the high complementary of solar PV production with its demand profile. As a result, there is no curtailment of VRE, nor any negative impact on reliability.

Contribution of each generation technology to system services in the Base and SolarPlus Scenarios, in 2019 and 2025



Notes: The contributions are for the Java-Bali and Sumatra systems together. The contributions to stability (inertia and spinning reserve) are calculated for the 100 hours with the lowest inertia. Inertia is based on the contribution from spinning rotors. Inertia and spinning reserves are among contributors to stability, although detailed technical studies are required to capture all of its components. Ramping is calculated from the contribution to the top 100 hourly ramps. Peak capacity/adequacy is based on the contribution to capacity needs in the modelled year. Energy is the share in annual generation. These measures aim to give an illustration of the diverse aspects of electricity security, but do not encompass all relevant components or potential technology contributions. Demand response is not included, though it has the potential to contribute to the services.

With the higher shares of VRE in the SolarPlus Scenario, the system will also become reliant on coal plants in meeting peak demand and ramping requirements, as well as in providing system services such as stability and balancing.

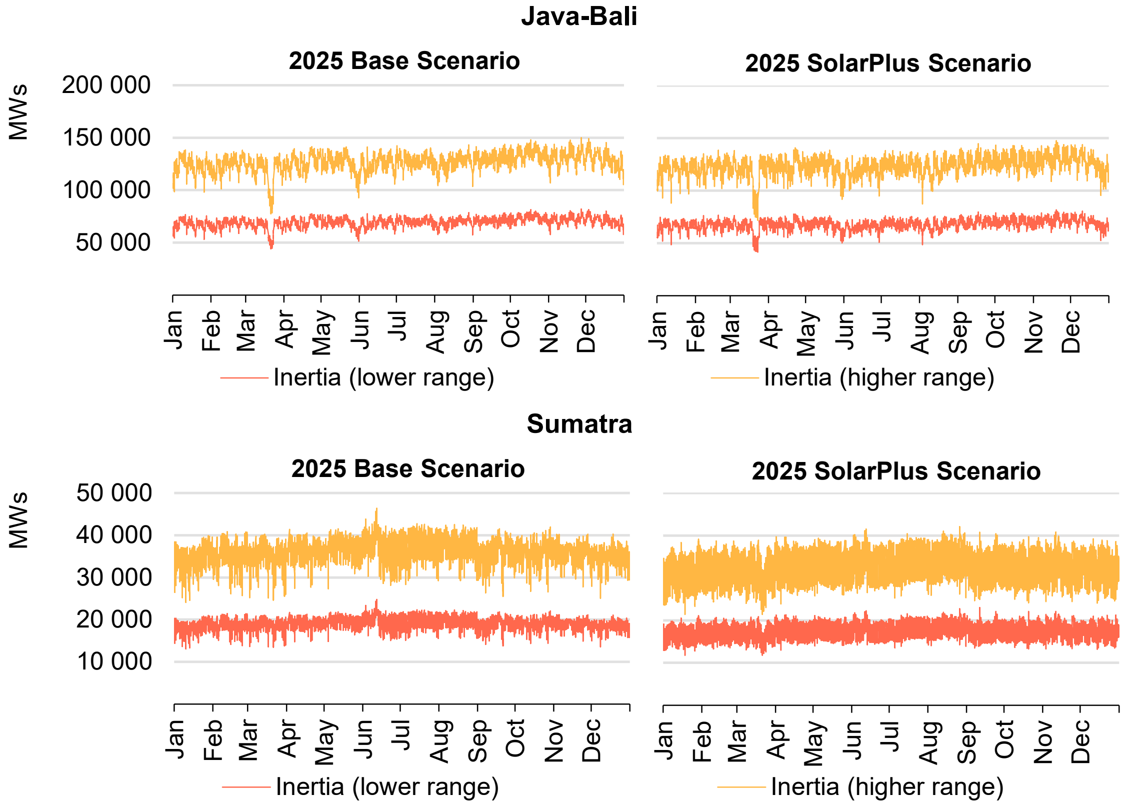
System stability is a potential concern as the penetration of solar PV increases. There are many components to stability, but the analysis focuses on inertia and to a lesser extent on the contribution to spinning reserves. In case of sudden imbalances, the inertia of online power plants supports system stability as it limits the rate of change of frequency by liberating kinetic energy from the rotating masses. If synchronous generators are taken offline and displaced by VRE, system inertia decreases because VRE is decoupled from the grid via inverters which do not inherently provide inertial services. Practices are however evolving and solutions exist.

In both the Java-Bali and Sumatra systems, inertia in 2025 in the SolarPlus Scenario is lower than in the Base Scenario. Given the large size of the Java-Bali system, inertia remains comfortable,[18] above 40 GWs, even in the lower range. The Sumatra system, on the other hand, is more vulnerable to the decline in system inertia due to the relatively small system size and the nature of the demand profiles. Thermal generators also play a role to damp oscillations through their power system stabiliser. Displacing these generators may also lead to a reduced capability to damp oscillations.[19]

One approach that has been used by many systems is to set up minimum level inertia requirements. A detailed grid stability study is required to determine such requirements, similar to the studies done in Ireland and Texas that have determined maximum penetration of non-synchronous generation and minimum inertia levels, respectively.

[18] A comfortable inertia level is about one order of magnitude higher than the minimum level required to ensure that the rate of change of frequency following typical outages (largest unit in the system) does not exceed the trigger value to disconnect generation (to avoid equipment damage) or shed load (to halt the frequency drop and restore the frequency).
[19] Inverter-based resources do not inherently provide stability services but can be designed to fulfil this role. In Great Britain, the system operator National Grid ESO successfully procured stability services from a wide range of resources including inverter-based generation.

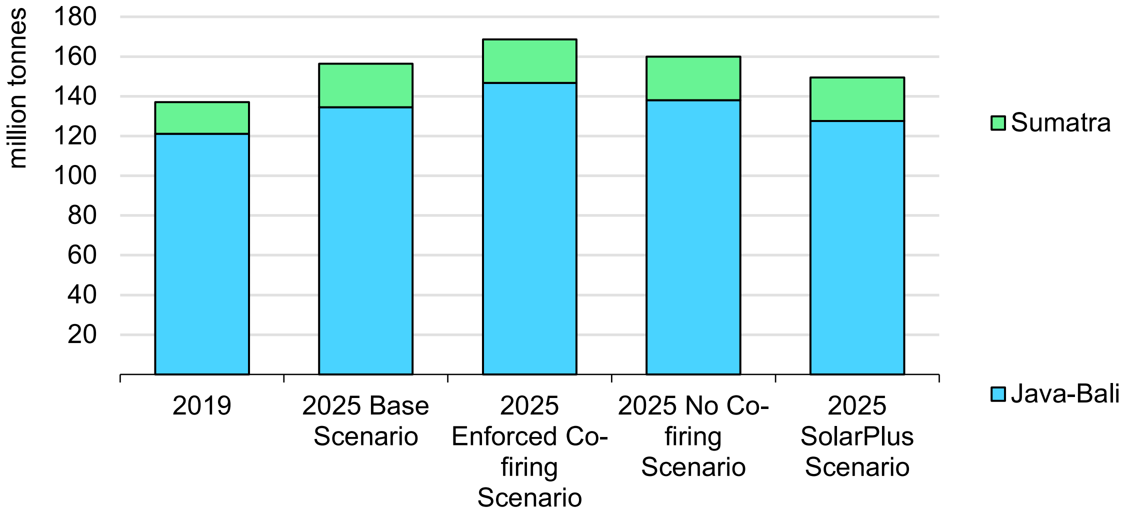
System inertia based on high and low inertia estimates of power plants in the Java-Bali and Sumatra systems in the Base and SolarPlus Scenarios, 2025



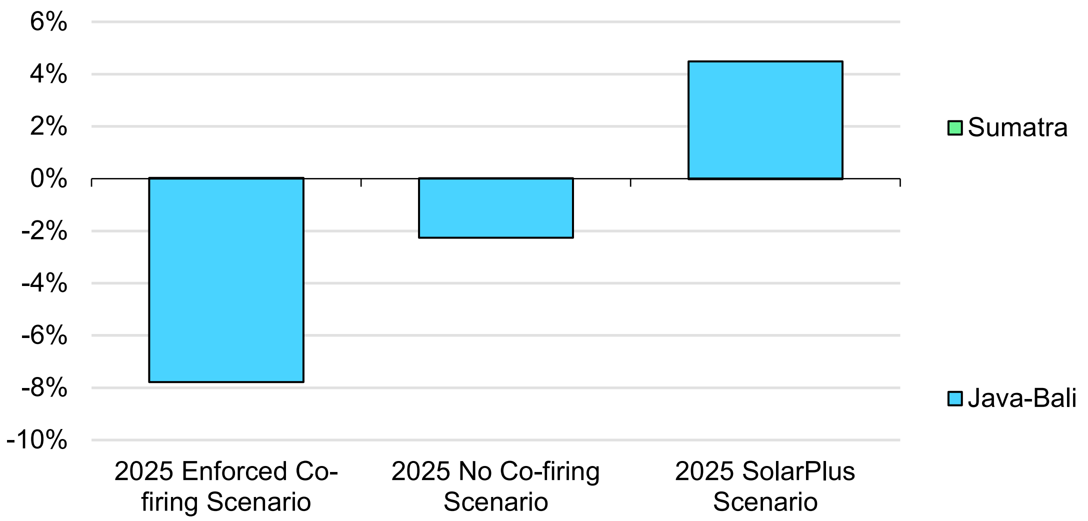
Note: Inertia estimates are based on the assumed inertia of each generation technology (coal plants 4-6 MWs; CCGT and hydropower 2-4 MWs). Detailed grid stability studies are required to provide a definite assessment of system inertia and specific requirements of the Java-Bali and Sumatra systems.

The higher share of VRE in 2025 under the SolarPlus Scenario will lead to a decrease in the **capacity factor** of coal plants and power sector emissions, compared to the Base Scenario, due to the replacement of a small portion (about 1 GW) of uncommitted thermal capacity, and the higher utilisation of more flexible gas-fired capacity. In the No Co-firing Scenario, the utilisation of coal plants further increases. This results in higher CO_2 emissions. In the Enforced Co-firing Scenario, emissions are even higher as coal plants are forced to run at the expense of gas plants.

CO_2 emissions in the different scenarios



Avoided annual CO_2 emissions in the scenarios compared to the Base Scenario

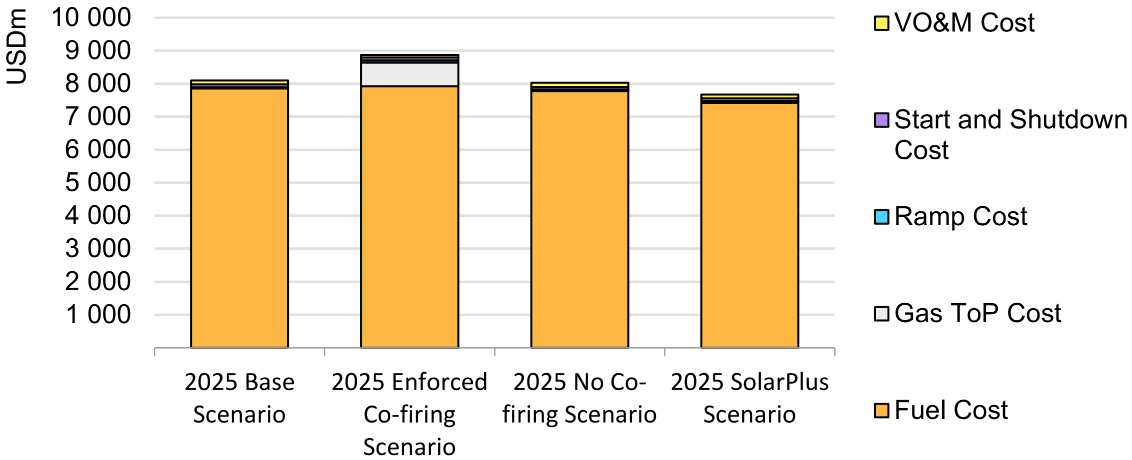


Higher shares of solar PV lead to lower operating costs

One of the results from deploying a higher share of solar PV in the generation mix in 2025 is the reduction in the overall operational costs of the system compared to the generation mix proposed the RUPTL. These operational costs consist of fuel costs, ramp costs,[20] start and shutdown costs, and variable operating and maintenance (VO&M) costs. While a carbon price, if included, would further improve the case for renewables, this was not considered to be implemented in 2025.

Replacing the non-committed plants as planned in the RUPTL (geothermal, hydropower, biomass, coal and gas) with solar PV in both the Sumatra and Java-Bali systems can lead to a net reduction in yearly power system operational costs of almost USD 430 million or 5.3% compared to the Base Scenario. The operational cost savings could be used for implementing flexibility measures to accommodate the higher share of solar PV, such as demand response programmes or ancillary services contracts with generators and industrial users.

Annual power system operational costs by cost category across all scenarios

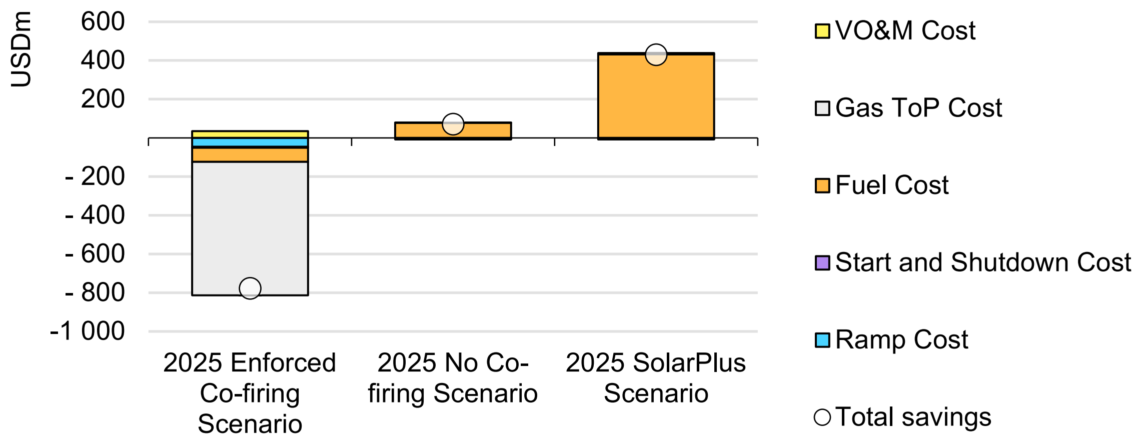


Note: Gas ToP costs and coal minimum offtake costs are the sunk costs related to unused resources according to contracts.

The main cost saving component in the SolarPlus Scenario is fuel costs due to the replacement of a small amount of uncommitted thermal generation (660 MW coal, 330 MW gas) on an energy basis by solar PV in addition to the replacement of the biofuel cost for co-firing. The fuel savings amount to USD 432 million (or 5.5%). On the other hand, the start and shutdown cost and ramp costs increase slightly since conventional plants are required to cycle up/down and start/stop more frequently to accommodate the variability of solar PV generation.

[20] The ramp cost reflects the wear and tear costs as a result of increased cycling. This cost is based on international data.

Annual system operational cost savings relative to the 2025 Base Scenario



Note: Gas ToP costs and coal minimum offtake costs are the sunk costs related to unused resources according to contracts.

The results from the scenarios with enforced co-firing and without co-firing show that the use of biofuels for co-firing has a cost premium attached to it, due to the higher cost of biofuels in comparison to coal. Without biomass co-firing, the annual operational costs would be around USD 66 million (or 0.9%) lower than the Base Scenario, as biomass is more expensive than coal. There is also large uncertainty as to what may be the actual cost of these biofuels.[21] Forcing the co-firing plants online to meet the 23% target with bioenergy comes at the expense of gas-fired generators that are not using the gas according to contractual volumes. This raises the costs significantly (+10% with respect to the Base Scenario).

Sensitivity analyses on total system cost components

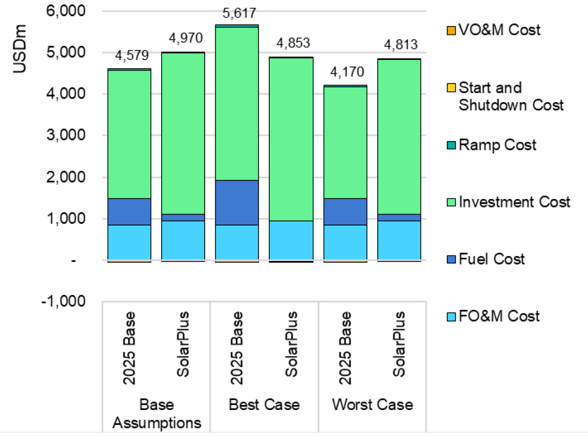
To address the key question of the competitiveness of solar PV, an analysis of the total system cost was performed. Firstly, the costs were compared between the Base and SolarPlus Scenarios, with a sensitivity analysis on some key parameters. Secondly, conditions were identified that would allow the SolarPlus Scenario to break even with the Base Scenario.

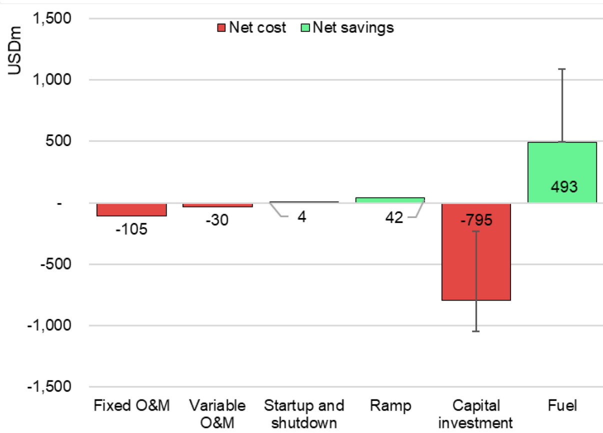
An initial comparison of the SolarPlus Scenario with the Base Scenario under a set of baseline assumptions shows a net spend of USD 444 million in total system costs when ramping up solar PV despite the lower operating costs. The main factors contributing to the differential between the two scenarios are the fixed operations and maintenance (FO&M) costs (USD 105 million per year, which

[21] Biofuels for co-firing consist of 9% wooden pellets and 1% residual waste. The costs of these fuels are based on costs from the Institute for Energy Economics and Financial Analysis (2021), Indonesia's Biomass Cofiring Bet. The cost of wooden pellets is estimated from the domestic market and from Viet Nam. The cost of residual waste is based on the average of community-scale and industrial scale costs.

include the periodic maintenance of the assets and are independent of the output of the plant), the additional investment (USD 795 million per year) and the savings from avoided fuel (USD 439 million per year).

Additional total system costs of the 2025 Base and 2025 Solar Plus Scenarios compared to 2019 (left) and net costs and savings of the 2025 Solar Plus Scenario compared to the 2025 Base Scenario (right)





Notes: As the SolarPlus Scenario involves replacement of non-committed power plants with solar PV, the Best Case Scenario assumes higher cost assumptions for fuel and CAPEX of coal, biomass, hydro and geothermal along with lower CAPEX assumptions for solar PV. Worst Case entails lower cost assumptions for fuel and CAPEX of non-PV plants, along with higher CAPEX assumptions for solar PV.

WACC=8%; VO&M costs = Variable operations and maintenance costs; FO&M = Fixed operations and maintenance costs.

Sources: Investment cost ranges from DEA (2021) Technology Data for the Indonesian Power Sector; NREL (2021) Cost Projections for Utility-Scale Battery Storage: 2021 Update; IRENA (2020) Renewable Power Generation Costs in 2020; Fuel cost ranges from IEEFA (2021a) Indonesia's Biomass Cofiring Bet; IEA Bioenergy (2019) Future Prospects for Wood Pellets Market; Argus (n.d) Indonesia International Market Prices; PLN (2021) RUPTL 2021 (baseline coal price = 70 USD/tonne and 55 USD/tonne for 5 000 kcal/kg and 4 200 kcal/kg, respectively); IEA Coal Market Report (2021).

A sensitivity analysis of three main parameters – fuel cost, CAPEX of solar PV, CAPEX of non-PV power plants – shows the comparative impacts based on how Indonesian energy policy might evolve in the coming years.

Fuel costs translate to net savings for the SolarPlus Scenario. Due to avoided cost of coal and other fuels such as biomass, the potential savings could amount to USD 562 million if the power plants were paying international market prices, instead of the artificially limited savings of USD 439 million due to the DMO price cap of USD 70/tonne.[22]

[22] Assumptions on baseline and maximum prices for the fuels are: biomass waste = USD 25 /tonne to USD 29.3 /tonne; biomass wood = USD 97.3/tonne to USD 115/tonne; bituminous coal = USD 70 /tonne to USD 90 /tonne; sub-bituminous coal at USD 55 /tonne to USD 84.5/tonne. The maximum market prices for coal uses the expected equilibrium price over the next 2-3 years instead of the current record high prices.

The CAPEX expenditure for new solar PV[23] relies on module and hardware costs (42% of total CAPEX) and soft costs such as developer margin and financing (23% of total CAPEX). At approximately USD 1073/kW, the cost of constructing utility-scale solar PV in Indonesia was higher than the global average of USD 883/kW in 2020. As highlighted earlier, local content regulations are estimated to increase the levelised cost of energy (LCOE) of solar PV by up to 50%. Allowing cheaper module imports from efficient manufacturing countries, relaxing tax and import duties, as well as developing financing and procurement strategies to lower the weighted average cost of capital (WACC) and other soft costs could allow Indonesia to lower the cost of investing in solar PV. If Indonesia manages to at least lower the CAPEX to the global average, it could lead to investment cost savings of up to USD 145 million. On the other hand, if supply chain issues push up the cost of PV modules, it could result in an additional USD 47 million in investment costs.

The CAPEX of non-PV power plants is also a factor in the feasibility of the SolarPlus Scenario. Avoidance of higher construction costs, which are likely, entail a comparatively lower investment cost for SolarPlus. Construction of new coal-fired power plants could face increased financing risks due to initiatives from global financial institutions to reduce new builds of coal and Indonesia's own net zero pledges. Likewise, investment in new geothermal and hydro capacities may also be higher than historic costs, since the best locations are already developed.[24] The most favourable situation for SolarPlus is when the CAPEX for coal, geothermal and hydro are higher while that for solar PV is lower. Meanwhile, the least favourable situation is when the CAPEX for non-PV plants are lower while that for solar PV is higher.

The 2025 SolarPlus Scenario would be more expensive with the baseline assumptions. However, it would breakeven with the 2025 Base Scenario if the following conditions were met: (i) the annualised investment costs for new coal-fired plants were at least 43% higher (USD 2 000 /kW) than the current baseline assumptions (USD 1 400 /kW), (ii) investment in solar PV is brought down to global average cost, and (iii) power plants were exposed to market prices of coal, gas and biomass.

[23] Assumptions on baseline, minimum and maximum CAPEX for solar PV are: USD 1 073/kW, USD 883/kW and USD 1 134 /kW (assuming a 10% increase in module costs and developer margins)

[24] The assumptions on baseline, minimum and maximum CAPEX for non-PV plants are: coal = USD 1 400 /kW, USD 1 400 /kW, USD 2 000 /kW; biogas = USD 2 651 /kW, USD 2 190 /kW, USD 4 356 /kW; biomass = USD 1 410 /kW, USD 1 109 /kW, USD 2 143 /kW; geothermal = USD 4 468 /kW, USD 2 704 /kW, USD 5 785 /kW; medium-hydro = USD 2 215 /kW, USD 1 203 /kW; USD 4 240 /kW.

This calculation illustrates the importance for the Indonesian authorities to figure out how to improve the competitiveness of solar PV. With an LCOE of USD 65/MWh, it is lower than the BPP-generation benchmark of USD 70.4/MWh, but not as low as 85% as stipulated in the ministerial regulation. Having a clear plan to deploy solar PV would support the growth of a local supply chain which, as it develops, could offer better rates. The authorities could also collaborate with international finance institutions to improve the investment environment for renewable capacities.

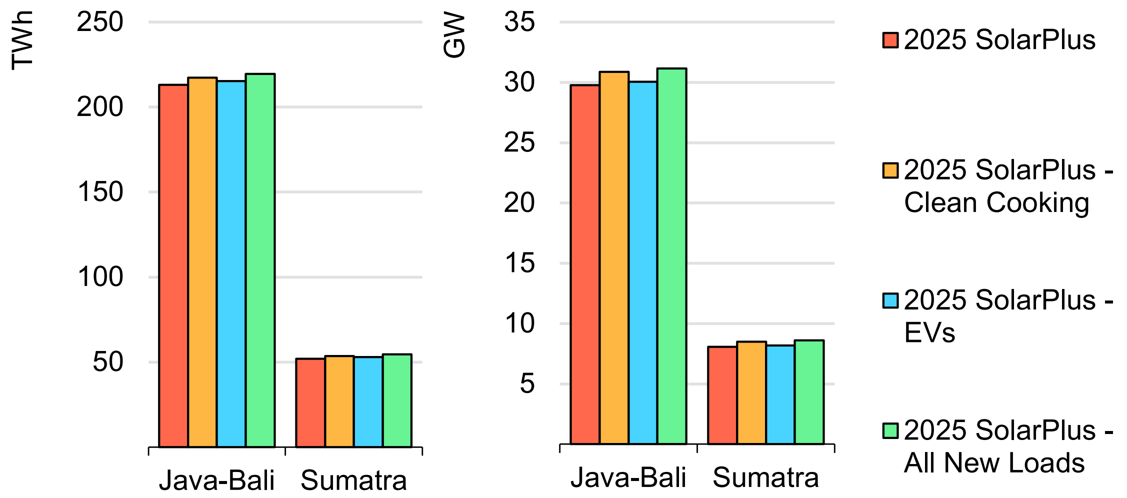
Electrification of end-uses can help accommodate more solar PV

Clean cooking (referring here to electric cooking) and electrification of road transport are part of the government strategy to decarbonise the economy, reduce imports of oil products and improve air quality. Both will increase the annual electricity and peak demand in both Sumatra and Java-Bali, although the load profiles of these end-uses are different.

The scenario with clean cooking assumes that one-fifth of households switch from LPG to electric cooking by 2025. This leads to an increase in demand and peak load by 2.2% and 4%, respectively, over the combined systems of Java-Bali and Sumatra. The scenario with EVs assumes 370 000 electric 4-wheelers and 11.8 million electric 2-wheelers by 2025, as per the government targets, and leads to an increase in demand and peak load by 1.2% and 1%, respectively, over the combined systems of Java-Bali and Sumatra. Non-managed charging is assumed, as tariff structures currently do not differentiate the time of use. Due to the existing thermal capacity, a system with an accelerated deployment of solar PV as in the SolarPlus Scenario could meet the demand with both clean cooking and EV deployment by 2025, without any additional capacity or demand-side response.

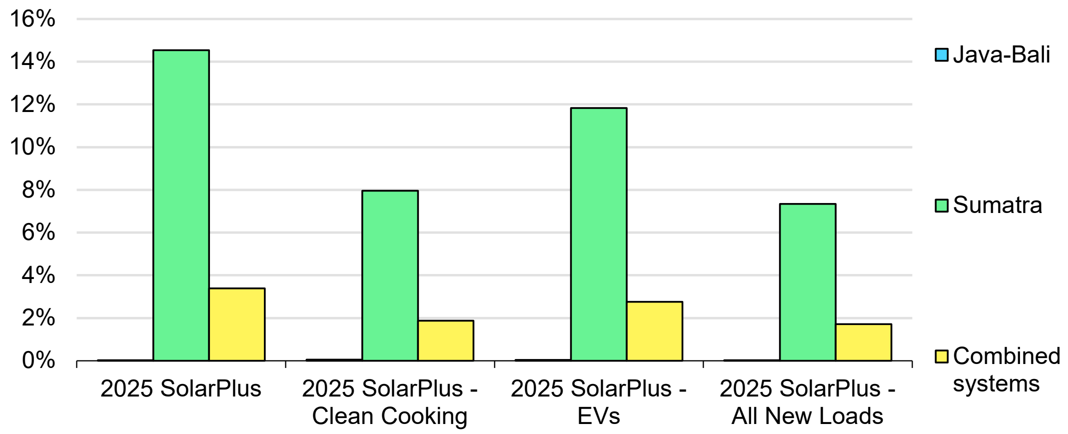
In this analysis, only the impact on emissions and solar PV curtailment are considered. Cost impacts are not studied. In particular, local grid reinforcements may be necessary, but the model does not contain enough details about the distribution network to perform a hosting capacity study. Such a study would be necessary for a complete overview of the opportunity for fast electrification.

Annual energy (left) and peak demand (right) in the Java-Bali and Sumatra systems with the electrification of new loads for clean cooking and electric vehicles in 2025



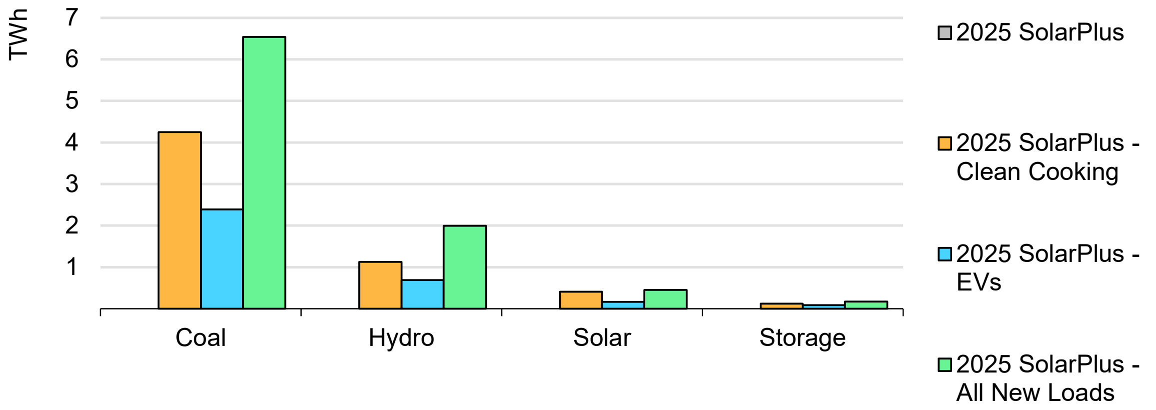
While curtailment in the 2025 SolarPlus Scenario was at 14% in Sumatra (and negligible in Java-Bali), increased electrification from clean cooking and EV deployment reduces this curtailment by 6% and 2%, respectively, as the demand at midday in Sumatra is also slightly increased.

Change in solar PV curtailment rate with newly electrified loads

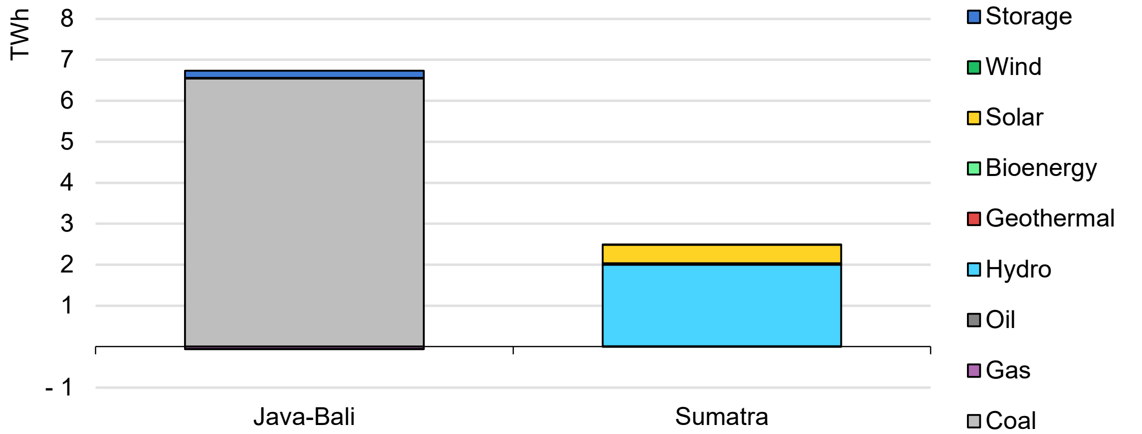


However, as the majority of the additional load is being met by dispatchable thermal capacity in Java-Bali, and almost exclusively coal capacity, the carbon intensity of the electricity system also increases. Meanwhile, in Sumatra, the majority of new demand is met by otherwise spilled hydro, with some of the demand being met by gas and a small amount of curtailed solar PV. When looking at the power sector alone, carbon emissions would increase in the Java-Bali system, and emissions would decrease in the Sumatra system.

Increase in generation by technology due to newly electrified loads, relative to 2025 SolarPlus

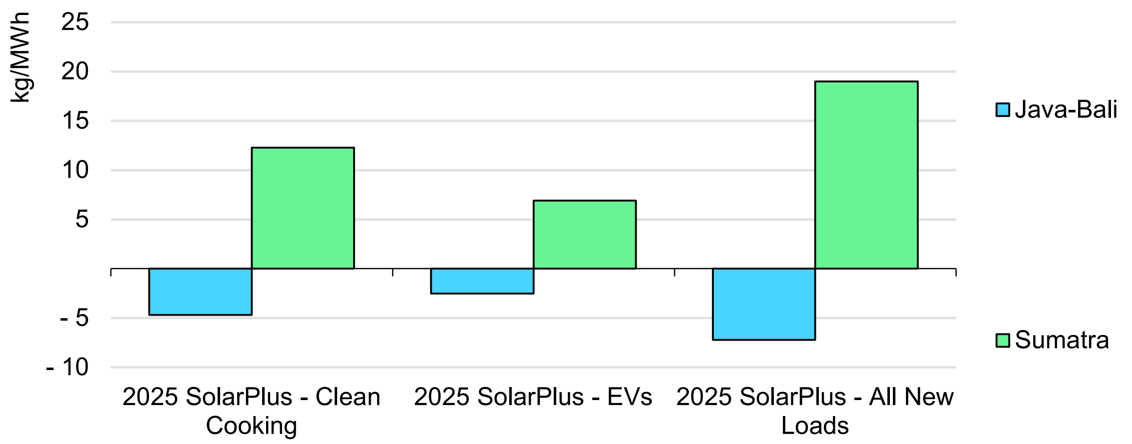


Increase in generation by technology for the Java-Bali and Sumatra systems when comparing a scenario with and without newly electrified loads under the 2025 SolarPlus Scenario



The increase in carbon emissions in Java-Bali highlights the need for faster decarbonisation of the power system to support environmental and sustainability goals when electrifying other new demands.

Reduction in carbon intensity of the power system with newly electrified loads, relative to the 2025 SolarPlus Scenario



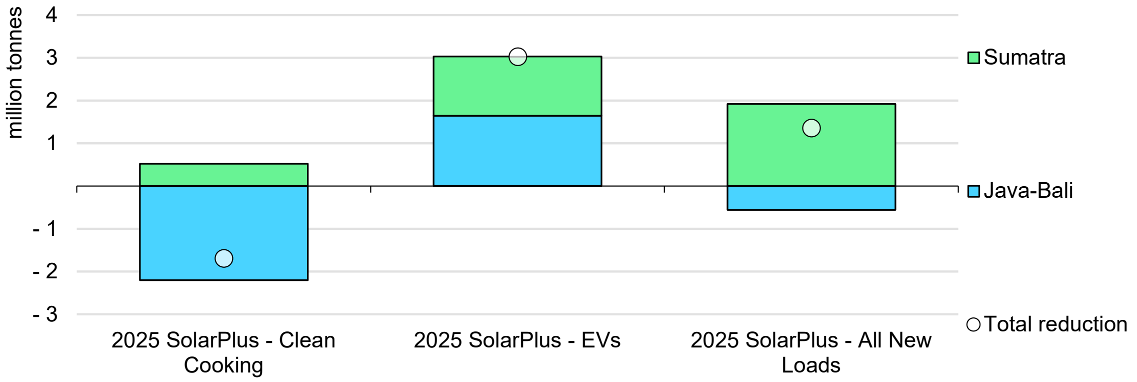
Note: In the 2025 SolarPlus Scenario, carbon intensity is 597 kg/MWh and 422 kg/MWh in the Java-Bali and Sumatra systems, respectively.

On the other hand, taking into account the avoided emissions from the otherwise LPG-based cooking and internal combustion engine-based road transport leads to a brighter figure. Reduction in emissions for road transport is particularly high, as electric mobility brings huge efficiency gains in motorcycles, at around 0.03 kWh/km compared to 0.16 kWh/km for internal combustion engines. Despite the high carbon content of electricity in Indonesia, the emissions from 2-wheelers are brought down from 38 $kgCO_2$/km for internal combustion engines to under 17 $kgCO_2$/km from electric motorcycles.

The emissions reductions from switching from LPG to electrified cooking are limited given the lower efficiency of electric cooking compared to LPG. If electric cooking replaces traditional biomass use instead of LPG, the reductions would be greater and would also include reduced NO_x and SO_x emissions.

If incentives are established to incentivise EV charging outside peak hours, especially during the day when PV infeed is the highest, more benefits can be delivered, leading to greater emissions reductions and lower curtailment rates.

Absolute reduction in carbon emissions of the energy sector with newly electrified loads, relative to the 2025 SolarPlus Scenario



Contractual flexibility of thermal plants enables a higher share of solar PV

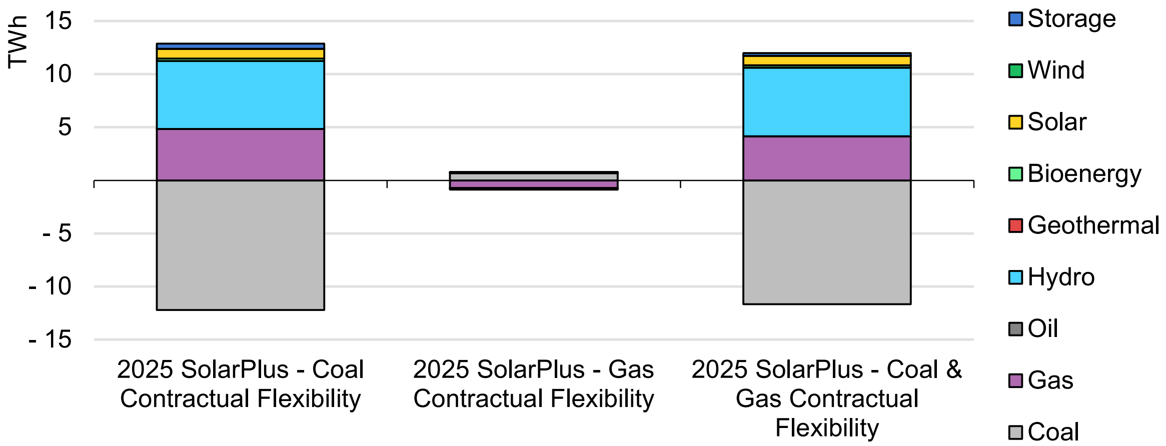
Inflexible contractual arrangements for the thermal fleet can limit the room for renewables in the generation mix due to distortion in the merit order dispatch, leading to less efficient operation of the system. All scenarios until now were constrained by three contractual inflexibilities assumed as follows: (1) a yearly capacity factor of at least 60% for coal IPPs (PPA inflexibility or coal contractual inflexibility), (2) a fixed daily gas offtake at the regional level (gas supply constraints or gas contractual inflexibility), and (3) output of thermal IPPs at any time set at 50% of the nominal capacity. The consequence of these constraints was spilled hydro from run-of-river plants and curtailment in solar PV, mainly in Sumatra.

Contractual flexibility would: (1) create more room for renewables by removing minimum offtake constraints on coal IPPs, (2) allow gas units to fully use their flexibility by operating with annual offtake constraints, and (3) allow newer IPPs to operate at lower minimum output levels, with faster ramp rates and shorter start-up times. With respect to the 2025 SolarPlus Scenario, relaxing these inflexibilities can lead to cost savings and emissions reductions as otherwise curtailed low carbon, low marginal cost generation is provided space to operate. The scenarios in the study consider removal of the first two constraints, as well as their combination. The third item is in any case recommended, as it does not carry additional cost and could improve flexibility, independently from the first two items. The cost benefit of removing these constraints is not addressed since the renegotiation of the contracts may come at a cost which is difficult to assess.

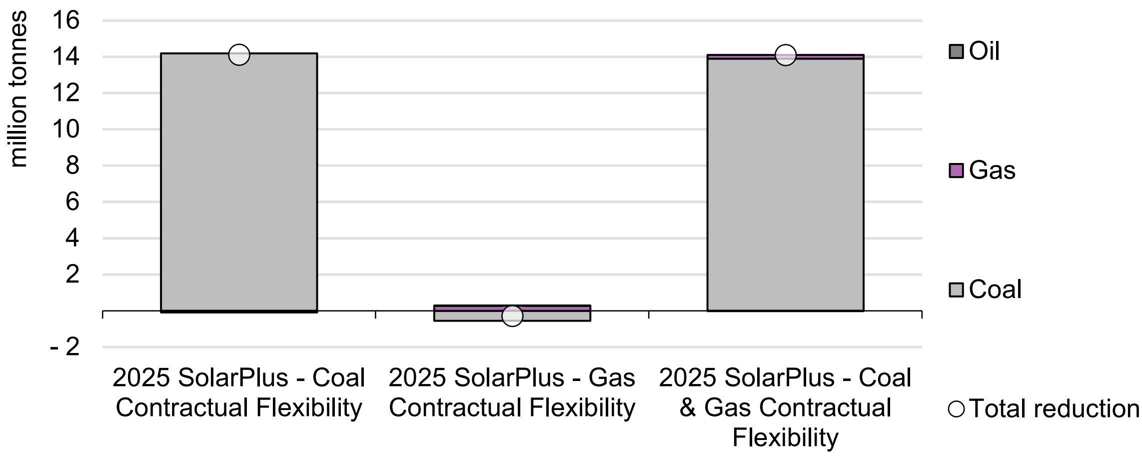
The constraint on the coal minimum offtake requirements appears to have the largest impact with respect to the SolarPlus Scenario. Removing this constraint leads to savings up to 14.2 tonnes of CO_2. Curtailment in Sumatra drops from 14% to negligible amounts (<0.3%).

Relaxing gas contractual constraints, moving from a daily ToP contract for gas offtake (per region) to an annual arrangement, without removing PPA inflexibility, would result in a part of the gas generation being displaced by cheaper coal generation and leading to an increase in emissions. This is because there is no carbon pricing. The combination of removing both inflexibilities, however, allows for both cost savings and emissions reduction benefits to be realised.

Change in annual generation by technology under different contractual arrangements with capacity according to the 2025 SolarPlus Scenario

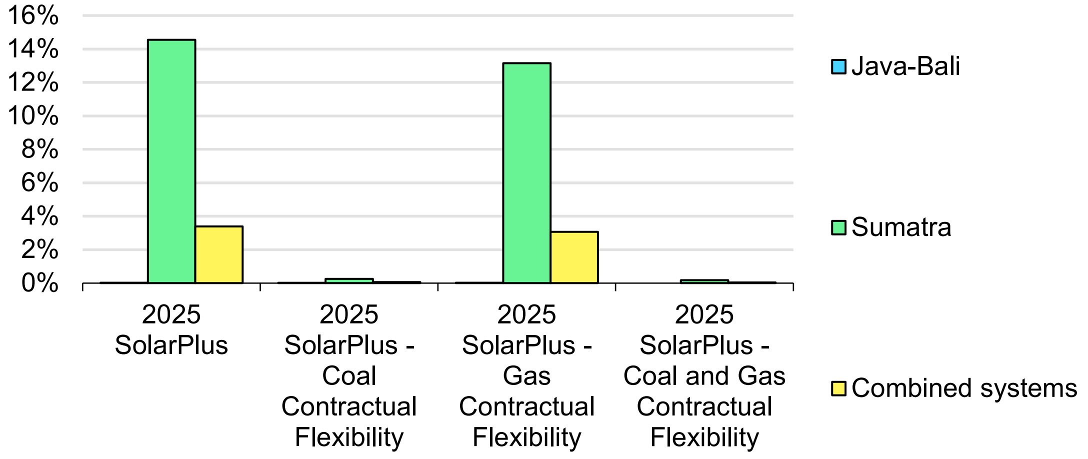


CO_2 savings by fuel type under different contractual arrangements relative to the 2025 SolarPlus Scenario



Note: The total emissions savings of the SolarPlus Scenario were 7 million tonnes compared to the Base Scenario, and 19 million tonnes compared to the Enforced Co-firing Scenario.

Comparison of curtailment under different contractual arrangements under the 2025 SolarPlus Scenario



Given this study's timeframe of 2025, the introduction of carbon pricing is not analysed. However, carbon pricing (if appropriately set) would start to favour efficient gas plants over inefficient coal plants in the merit order. A consequence is that gas infrastructure could be supported without the current ToP mechanism in gas supply contracts. The introduction of carbon pricing and the moving away from ToP could thus happen simultaneously, supporting both renewables and increased system flexibility. This would further liberate gas for sale on the international markets.

Review and discussion of assumptions

This study illustrates a number of possible trajectories to meet the 2025 renewables target and the impact of some key sensitivities. The quantitative outcomes depend on a number of assumptions and could be improved with actual data. However, the qualitative conclusions appear robust, as well as the order of magnitudes. For completeness, a few assumptions are discussed here.

The electricity demand in all scenarios is based on the RUPTL 2021. It was stated in Chapter 2 that optimistic demand forecasts in the past are among the reasons for the over-built thermal fleet and pose a barrier to integrating new RE generation. If demand in 2025 is below the RUPTL projections, the existence of the contractual and technical constraints at the thermal power plants means that the share of renewables in the electricity mix and the potential benefits of all the alternative scenarios are reduced.

Technical and contractual constraints on thermal generators have a significant impact on the results. The instantaneous minimum output of coal generators was set at 50%, which is a little higher than the technical capability of modern plants. Changing this value has limited impact. The yearly capacity factor of coal IPPs was set at 60%, a value at the lower end of the range experienced in neighbouring countries. If actual PPAs were even more inflexible on the value of the minimum take obligation (for example, 65-70%), the share of renewables in the electricity mix and the potential benefits of all the alternative scenarios would be reduced, except for the scenario illustrating the impact of removing the contractual constraints.

Chapter 4. Solutions for enhanced power systems

Recommendations for enhancing the power system

- To support its ambitious sustainability targets, Indonesia should make an actual commitment to renewables in the power sector and put them at the centre of planning: set even more ambitious targets, improve their competitiveness (not only as an industry product but also as a means of electricity generation), and adapt planning and operating practices to take into account their characteristics.
- Given the inhibiting role of contracts on the flexibility of the young and large Indonesian thermal fleet, there is a real urgency to enter into a contract reform for coal-fired plants, possibly in parallel with a coal phase-out programme. To capture efficiently the latent flexibilities from generation assets, the new contracts should move away from energy-only pricing towards a pricing that values better the system value of the plants with, at least, a part that capture the role in meeting peak demand.
- Renegotiation of existing contracts may be difficult; it should be supported by an in-depth analysis of the flexibility needs for the next decades (at least until 2040) and take into account the evolution of the thermal fleet and the benefits of smart technologies and practices which may be introduced progressively in the coming years.
- In the perspective of future VRE growth, operation efficiency would benefit from deploying closer to real-time operations with system-wide forecasts of wind and solar power, and dispatching and activation of reserves in intraday.
- The MEMR can learn from PLN's smart grid pilots when designing Indonesia's own smart grids strategy which relies not only on new hardware, software and algorithms, but also on new skills and enhanced planning and operating practices.
- In the next decades, Indonesia will need more grid infrastructure to accommodate the demand growth and more VRE: incentives can be deployed not only to build more grids (and attract private financing), but also to use the assets efficiently through enhanced planning and operation practices.
- More transparency in the planning process under the RUPTL and the allocation of projects and contracts by PLN would bring benefits through increased stakeholders' confidence and better assessment of the value of new assets and resources.

Providing access to clean, secure and affordable electricity to all Indonesians will require the government, state-owned companies and private companies to work together and deploy the wide range of solutions needed to improve – on the one hand – the efficiency of the large systems and – on the other – the quality of electricity in smaller systems or remote areas. Enhanced institutions and practices – at various levels – will play a critical role in achieving both objectives.

The previous chapter showed that the systems of Java-Bali and Sumatra are able to accommodate enough solar PV to fill the gap between the committed renewable generation and what is needed to meet the 2025 RE targets. In 2025, the annual share of solar PV would then be approximately 10% (compared to 2% in the RUPTL 2021). More ambitious levels of VRE would require the development of more extensive and smarter grids. While investment in assets is an essential part of Indonesia's transition, a good share of progress can be made without significant investments in infrastructure by making better use of the existing assets. In this chapter, we present a range of solutions aimed at helping Indonesia deploy more VRE and meet the country's sustainability goals. These solutions span across the "hard" (equipment and infrastructure) and the "soft" (commercial structures and improved practices in planning and operations) aspects of the enhancements to the Indonesian power sector.

New contractual structures can harness the flexibility potential of Indonesia's thermal fleet

A power system may have the technical capabilities to provide adequate flexibility but, due to commercial structures this flexibility cannot be utilised. This is the case in Indonesia. Aligning commercial flexibility and technical flexibility would enable Indonesia to transition to a clean energy system and integrate a higher share of low-carbon resource.

The PPAs which require PLN to take power from the IPPs well above the minimum stable levels of the unit and to guarantee a given capacity factor are a significant cause of inflexibility. In theory, **additional contracts for flexibility services** could be added on top of the physical PPAs. However, this would imply an additional payment which may not be the most cost-effective way to integrate VRE.

The operating characteristics of power plants (for example: start-up time, stable minimum operating level, ramp rates) can be a barrier especially for older thermal assets. These assets can be retrofitted to ensure, for example, lower stable minimum levels and higher ramp rates, which in turn would make these assets more valuable in a clean energy transition to allow integration of variable renewables. It is noted that the coal fleet of Indonesia is relatively young compared to the average age of coal-fired power plants globally.

In Thailand, it was found that retrofitting power plants to enable lower minimum stable levels and faster ramping, while valuable, was less cost-effective compared to the relaxation of contractual constraints. The costs and benefits of all options must therefore be considered.

The long-term contracts for gas supply, which include ToP clauses, are another cause of inflexibility. Due to these clauses, the gas supply is a sunk cost, altering the merit order of the units in the dispatch.

Strategies to introduce new contractual structures

In order to identify pathways to increase contractual flexibility, it is important to understand what level of flexibility is needed and what the barriers are for the Indonesian system, specifically. Detailed information regarding the payment structures and/or minimum take obligations in the PPAs with the coal generators could support a more detailed assessment of the contractual barriers. This could be the scope of a later study.

When contractual structures limit flexibility, two main strategies exist:

- let contracts run out and make changes only in new contracts, including renewals of old contracts
- seek to renegotiate current contracts as well as make changes in new contracts including renewals of old contracts.

Irrespective of which of the two strategies is deployed, it is important to start preparing new contractual structures, such that any new contracts between PLN and generation assets are more flexible and better suited for higher shares of VRE.

Key factors that need to be considered in order to understand which of the two main strategies is most applicable include the duration and extent of the impact of inflexible contracts. In a situation where the contractual structures are about to naturally run out, it is preferable not to renegotiate contracts.

Flexible contractual features

Best practices for new contractual structures can be explored in future work. These would build on the principles provided here. For thermal assets, the following principles can be applied to contracts to increase flexibility:

- separating physical production guarantees from budget stability
- lowering minimum take obligations

- lowering minimum run rates to match the technical capabilities
- implementing differentiated price incentivising flexibility
- implementing budget security instruments, such as floors on settlement irrespective of generation
- providing financial incentives for retrofits of older plants to increase flexibility
- separating contracts for system services from the supply of energy.

For renewable energy, the following contractual features support flexibility:

- clear procedures for curtailment
- clear settlement rules for curtailment (for example, with compensation)
- mechanisms that incentivise system friendly deployment,[25] including system services
- forecasting requirements.

Approach to renegotiating existing contracts

In cases like Indonesia, where contractual structures will continue to significantly limit the system flexibility for many years, renegotiation should be considered. Renegotiation needs to be done with extreme care in order not to negatively impact the investment climate since it can increase the required return of investment on future assets, and thereby increase the cost of the clean energy transition. This should be co-ordinated with efforts towards coal phase-out.

When renegotiating, it is important for governments to understand that the main goal is to optimise the overall cost of the system in the long run rather than trying to save as much money as possible on each individual contract. This is to avoid long-term consequences on investor trust, which can make the transitions less affordable. Transparent renegotiation will build investor confidence even though existing contractual structures may be changed or to some extent bought out.

Stakeholder consultation is a key component of contract negotiation, one in which capacity building among asset owners, system operators, financial institutions and policy makers can play a key role. It is important to consult both asset owners and financial institutions in order to understand the most important factors for them in the process. For example, asset owners may be willing to accept lower guaranteed take obligations if they are compensated with differentiated prices, but this may not be acceptable for the financial institutions.

[25] System-friendly deployment: promoters are incentivised to invest first in resources that have the highest value for the system, for example, those which minimise the need for additional grid assets or which produce at times when the system needs it the most.

It is important that all stakeholders understand the system needs, and also which options can contribute to flexibility from contractual, technical, operational/process and policy perspectives. For example, financial institutions may need capacity building in order to be able to evaluate how reduced minimum take obligations will affect the risk profile of the investment.

One approach that can be helpful when renegotiating contracts is auctions. If the needed flexibility is well defined, then auctions can be held with the new contractual structures, and assets can bid in the needed compensation to change contractual structures to increase system flexibility. In the auction, the needed amount of flexibility can be defined such that not all contracts have to be renegotiated. Additionally, the competition element of the auction will ensure that the renegotiation will be done most efficiently, meaning that the contracts that require the lowest compensation are the ones that will be changed. There can be differences across assets' willingness to restructure due to different factors like investor risk appetite, ratio of debt versus equity, technical capability, etc. The auction design determines the success of the auction. If the design and process are not carefully considered and aligned to the desired outcome, auctions can prove unsuccessful.

Governments have different financial abilities to renegotiate contracts. In the case where financial resources are limited, it is even more important to prioritise which contracts to renegotiate in order to maximise system flexibility. In order to do this, a detailed understanding of the need for flexibility, as well as a thorough understanding of the elements of the contracts that limit the utilisation of existing flexibility are required. Additionally, governments should seek to collaborate with philanthropy, development banks and other governments in order to increase the financial ability to restructure contracts where needed. An example of this is ADB's Energy Transition Mechanism which includes efforts for early retirement of coal plants in Southeast Asia.

In-depth assessment of needs can support Indonesia's own smart grids strategy

The study in Chapter 3 explored the flexibility requirements in 2025. Given the need for long-term contracts for investors in new renewable capacities, a study of the flexibility requirements over a longer period, at least until 2040, would support the efficient renegotiation of contracts. Beyond the current decade, a number of other enhancements would add to the current flexibility resources. These include smart technologies and enhanced practices for planning and operations.

Digitalisation opens up a wealth of opportunities in the power system

Digitalisation contributes to unlocking technical flexibility from a wide variety of resources. Digitalisation is the application of powerful information and communications technologies in equipment, analytics and user interfaces. Examples of digital enabling technologies in today's energy systems are smart meters, digital sensors in generation and on grids, drones (robotics) and "digital twins" (a digital simulation of a real-life asset to enable the virtual testing of features, feasibility and durability). Digitalisation is at the heart of the power system transformation since it offers opportunities in all the segments of the value chain, from the generation of electricity all the way down to the final consumer, who can be empowered to play a bigger role. In a "smart grid", information is exchanged between all interested stakeholders, enabling them to make optimal decisions.

Smart grid applications and benefits in a nutshell

Utilities have been at the forefront of digitalisation through data and automation, and corrective control means. Potential benefits span a wide range of applications.

Generation: Digital upgrades to power plants can improve efficiency and resilience: a key application is assets performance monitoring. Predictive maintenance uses advanced analytics to closely monitor and analyse equipment so that potential problems can be identified at an early stage and repairs can be carried out before failures happen. This significantly reduces unplanned outages and downtime. The IEA estimates that over the period to 2040, digital equipment could deliver an average 5% reduction in power operations and maintenance (O&M) costs, and an average 5% improvement in performance.

These gains in operation optimisation would also bring savings in new investments: if the lifetime of all the power assets in the world were to be extended by five years, (considering all assets, including grids and generation) close to USD 1.3 trillion of cumulative investment could be deferred over 2016-40 globally.

In the case of variable renewable plants generating power from solar and wind, a layer is added to forecast generation from weather data and to optimise the contribution from VRE plants to the system. Often connected to the grid through power electronic interfaces, these plants are flexible and can contribute to grid management, for example supporting local voltage and modulating down output power to avoid congestions. Since 2003, Spain's Iberdrola's CORE (Renewable Energy Operation Centre) has been displaying the benefits of technology to monitor renewable generation remotely.

Grids: Power system flexibility is a cornerstone of electricity security in modern power systems. The grid plays a central role in unlocking flexibility from power plants, energy storage and demand-side resources. Digitalising electricity networks is essential to pool all available flexibility sources.

Digital substations are making operations more efficient and the system more resilient. New generation supervisory control and data acquisition (SCADA) and EMS are incorporating advanced functions facilitating grid management. Finally, more flexible planning practices and close-to-real time operation take advantage of short-term weather forecasts to minimise RE curtailment and maximise the generation from RE sources. Red Electrica de Espana's CECRE (Control Centre of Renewable Energies) monitors all renewable units above 5 MW in Spain and supports the seamless penetration of renewables. Dynamic line rating (DLR), for example, helps make better use of existing transmission corridors thanks to more accurate assessment of their real-time capacity.

Distributed generation and consumers: Smart meters and digital investments provide better visibility of the distribution grid and consumer uses. This reduces non-technical losses and interruption times.

Digitalisation also allows harnessing the flexibility potential from final consumers located at the low and medium voltage levels. While only a minor part (15%) is used today, the IEA estimates the demand response potential in 2040 at 6400 TWh – which is 20% of the total energy consumed.

Real-time communication through smart meters can lower peak demand by affecting buildings consumption and shifting EV charging times. Auto-consumption can also contribute to lower RE curtailment where the DG hosting capacity of local grids is a constraint.

Reinforcing the institutional framework around smart grids

To support Indonesia's sustainability goals, the MEMR mandated PLN to develop a **smart grid programme** through Presidential Decree 18/2020 with the target to develop five "smart" distribution networks per year in Java-Bali from 2020 to 2024. PLN's smart grid roadmap runs in two phases. In 2021-2025, the focus is on reliability, efficiency, customer experience and grid productivity. From 2026 and beyond, the focus is on resilience, customer engagement, sustainability and self-healing. This programme includes a dozen pilot projects and a roadmap for deployment of advanced metering infrastructure over the 2021-2025 period and beyond. PLN has already achieved some success in deploying digital technology in two substations and advanced analytics in dispatching centres.

The Indonesian institutions and MEMR can take a stronger role in smart grids. Although utilities have a major role in building the digital infrastructure and leading the associated developments, the authorities are in charge of deploying policies and the right incentives to ensure that the benefits of smart grids are shared along the value chain. To fill this role, the MEMR should lead – in collaboration with stakeholders – the **development of a vision and roadmap**, initiate programmes, perform monitoring and adopt the needed regulations and standards.

India provides an example. The Indian Ministry of Power has established a national smart grid mission (NSGM) with a leading role across the country (Government of India, 2015). NSGM's implementation framework has four pillars: (1) Develop a vision and an institutional structure: define the governance, set the goals and control the operational budget; (2) Establish standards and the policy framework: the necessary standards required for information technology and operational technology for smart grids; (3) Develop business models and catalyse investments; and (4) Monitor progress in achieving the goals and report to the Ministry. India's know-how in smart grids has enabled it to become recognised today as one of the leading parties in the international smart grid network ISGAN, and the country hosts a Smart Grid Forum.

Smart grids are also an opportunity for PLN to expand their value offering by providing **services to consumers to reduce their consumption** (and thus bills) and benefit the system while aiming to achieve the sustainability goals. These services could help consumers buy energy-efficient appliances (supported by long-term contracts with manufacturers) or implement automation services, such as energy management systems or smart appliances. These services can be provided by separate businesses called energy service companies (ESCOs). Energy performance contracts (EPCs) between the customer and the supplier may include the replacement or deployment of equipment, and the supplier is often rewarded through capturing a part of the customers' energy savings.

These services may seem difficult to combine with the traditional business model of the utility: the sale of electricity as a commodity may decrease, thereby decreasing the corresponding revenue streams. On the other hand, this new value offering is in line with the growing expectations of consumers for an energy supply that is of higher quality and more environmentally friendly while remaining affordable. Furthermore, the supply of electricity to consumers is currently subsidised. Appropriate regulatory incentives may help the state-owned utility to see benefits in these services and to deliver them. Given PLN's footprint in the electricity sector, incentives can be of macroeconomic nature (related to targets of power consumed per unit of economic output) or related to targets of improved power efficiency in selected sectors and industries.

A long-term smart grid strategy building on processes and people to ensure the successful use of deployed hardware

There are many benefits to digitalisation in power systems. Indonesia should, however, identify the applications that deliver the best value in its own context, based on the power system framework and its priorities for the next decades. For example, as the current pricing scheme does not incentivise consumer flexibility, investment in smart meters may deliver little benefits.

While driven by technology, the deployment of smart grids should be seen as a **holistic effort of the power sector towards digitalisation that builds on solid institutions and enhanced processes**. Smart grids are not only about assets, methodologies and algorithms. These need to be supported by staff with the right skills and operational procedures that make use of the benefits of the technology. Operational procedures may need to be updated or developed to ensure proper use of the new and existing technology. Staff also need to be trained in new skills, such as data management and data interpretation. For example, as data flow in and insights are provided on the health of assets on a continuous basis (instead of during periodic revisions), procedures should be in place to initiate an intervention on a deteriorating asset in a reasonable timeframe and to quickly adopt the required operational changes.

Indicators are needed to measure the successful use of deployed hardware. While PLN has targets for the deployment of digital infrastructure and equipment, it is equally important to ensure that the deployed equipment is used efficiently.

Sharing information with interested stakeholders will benefit the system, but cybersecurity grows in importance

Digitalisation will deliver new and more abundant information, thanks to remote monitoring and analytics, that utilities could use to improve the quality of their service and efficiency. Access to transparent and up-to-date information about the system also allows stakeholders to make optimal economic decisions, such as investing in the needed resources that help the system. The information shared can span a wide range: raising awareness of the current projects and achieved benefits (such as the public smart metering implementation dashboard from India), providing information on support schemes and the way risks are managed, explaining how data security and privacy are ensured, listing channels for implementation support, and providing real-life data to support business cases.

On the other hand, digitalisation requires utilities to deploy new skills in **cybersecurity** and a legal framework to ensure data privacy.

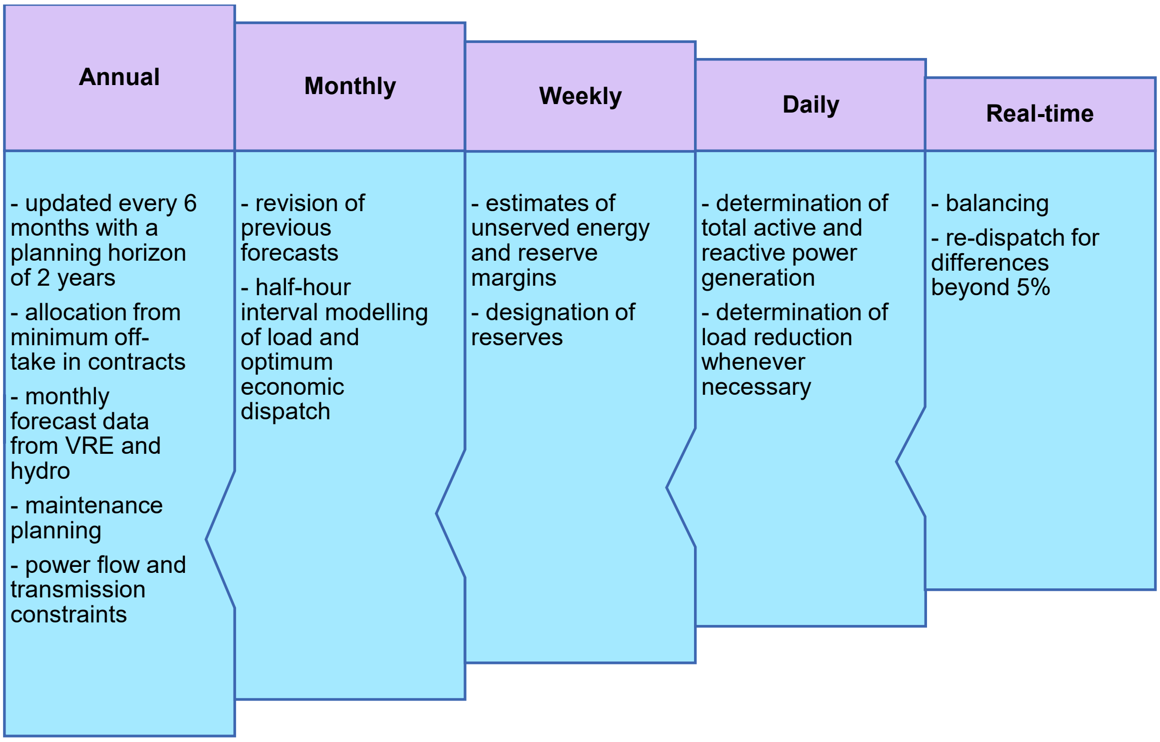
Enhanced operating practices can help realise the full benefits of technical and contractual flexibility

The removal of barriers from contractual structures and the deployment of smart grids will have clear benefits for system security and flexibility. Substantial enhancements could be achieved without major investment, through improved operational practices. Increasing the share of VRE would require not only improved operational planning, but also modern operational practices, which would also lead to revision of the existing grid code. Forecasting and flexible resource requirements would change the traditional schedule of operations especially for countries that rely heavily on baseload generation, as does Indonesia.

Indonesia has already made some steps to modernise its system operations. It previously had different grid codes for the different power systems (Regulation 03/2007 applied to Java-Madura-Bali and Regulation 37/2008 applied to Sumatra). They were consolidated in 2020 under MEMR Regulation 20/2020,[26] along with laying out provisions for variable renewable energy. The Connection Code is a key instrument to harness flexibility from new power plants of all sizes including VRE plants. To accommodate the increasing VRE penetration, the connection codes could be further improved with specific, forward-looking requirements in order to maintain the security of the system. Key technical aspects to enhance system flexibility include ramping, voltage control, frequency response, power quality, frequency regulations and fault ride through. Reasonable requirements in the Connection Code (differentiating size and connection voltage) can provide large flexibility at low cost and which can be harnessed later.

[26] Regulation of the Minister of Energy and Mineral Resources number 20 of year 2020, on network rules for electric power systems (Grid Code).

Schedule of power system operations



Source: IEA analysis of MEMR (2020), Indonesian Grid Code.

Short-term forecasts and intraday scheduling to enable better use of the existing resources

PLN dispatches generating resources according to their marginal cost and schedules submitted by 10:00 for the day ahead. VRE operators also submit real-time data and a daily forecast with a resolution of 15 minutes, updated every 6 hours.

Moving scheduling and dispatch closer to real time would allow for a more accurate representation of variations of net demand (demand minus non-dispatchable generation). In addition to the existing day-ahead process, an intraday unit commitment would result in a more efficient use of reserves because a larger portion of the VRE variability is absorbed by the updated schedules and does not need to be balanced by reserves. A new operational function focused on intraday planning and scheduling can be considered to assist with forecasts and manage intraday generation schedules. Centralised system-level forecasting of VRE generation can improve system operation by enabling the system operator to account for overall variability of VRE outputs across the whole system and accurately predict the amount of VRE generation available. This system-wide forecast would complement the plant-level forecast and allow design incentives to improve the quality of the forecasts submitted by VRE operators.

Improving reserves procurement to incentivise flexibility

Currently, reserve requirements are deterministic, based on the size of credible outages. PLN enters into mid- to long-term contracts with conventional generation and interruptible load to ensure their availability.

An increased granularity of reserve products and close-to-real-time procurement can improve cost efficiency. Timing refers to both the balancing reserves interval and the forward time of procurement (time between gate closure and delivery). A shorter interval decreases the volume of reserves required due to schedule changes, but also complicates procurement. For balancing markets to tap into all of the relevant sources of flexibility, the rules set for participation need to carefully address the access requirements including minimum resource size, technical capabilities and resource type. Appropriate requirements – for example asymmetrical products (separate products for upwards and downwards reserves with different requirements) – can open participation by VRE but also demand response (including EV charging) and distributed energy resources (at least, through aggregators). Appropriate steps are needed to monitor these new products as the quality of the reserves may decrease (typically, if a service is provided by units not equipped with the detailed telemetry and metering capabilities to meet the current requirements). The pricing structure would also need to be adapted.

Monitoring and forecasting dispersed resources to bring light to variability

Sufficient observability of resources meant to grow in the future will deliver benefits in the future. This applies to VRE (both dispersed and utility-scale) and to electrification of new end-uses such as EVs, air conditioning and electric stoves. There is no immediate need for a massive investment in digital infrastructure to enable VRE penetration. It is possible to derive substantial value through deploying measurement devices at selected units and extrapolation of available data. Similarly, VRE forecasting tools use sensing technologies, together with mathematical models, to accurately predict wind speed and solar irradiance, and subsequently forecast outputs from VRE plants on a sub-hourly basis.

New reliability standards to support VRE

Following the 2019 large-scale blackout in Java-Bali, which left millions of citizens without electricity for hours and up to a day in some areas, the Indonesian reliability framework has been improved. The grid code and the distribution code are now the key references for system operations. In transmission, the N-1 criterion is the standard. A spinning reserve must be kept matching the size of the largest online generator. A defence plan is in place with manual and automatic shedding to prevent frequency instability. Interruptible contracts represent 20-25% of total consumption. At least 30% of the load can be shed automatically.

On the other hand, reliability and reserves requirements are static and do not take VRE into account. PLN is required to maintain a 35% reserve margin. This criterion contributed to the overcapacity in thermal generation and additional challenges for VRE. As the transition proceeds, the static reserve margin on generation should leave room to new metrics, eventually taking into account **probabilistic aspects** when VRE sources become significant. The most common metrics are the expected energy not served (EENS), expressed in MWh per year, the loss of load expectation (LOLE) and loss of load probability (LOLP) for a specified ENS volume, both expressed in hours per year. No single reliability metric and standard can capture all types of events, from situations where customer shedding is to be performed preventively in order to shave peak load during a rare instance of very high demand, to large-scale outages affecting customers for several hours to days.

The proposed framework to establish or revise reliability metrics is as follows: The competent authority (in the case of Indonesia, the MEMR) needs to decide what are the events that have to be prevented; as a corollary, what events/damages are acceptable for the society and how often. This results from consultations with field technical experts. From this decision, it is then possible to set the policy objectives and update reliability standards and metrics accordingly. There is a balance to be found between the security standards and their cost. Therefore, the set standards are to be monitored continuously and reviewed periodically.

Enhanced planning practices to support the power system transformation

Adapting reliability standards to take into account the nature of VRE will affect operations and planning. But VRE is not the only major change. End-use electrification such as EVs and electric cooking increase the demand for power but the nature of these new uses also offers opportunities for flexibility. Therefore, system planning practices could be improved so that a long-term flexibility strategy is developed and implemented. Various instruments can be combined to unlock the needed flexibility such as grid codes (in particular, grid connection requirements), financial incentives and enhanced operational practices.

Co-ordinated and integrated planning, such as the Australian Energy Market Operator's (AEMO) bi-yearly Integrated System Plan (ISP), which serves as Australia's whole-of-system plan for the next 20 years, provides collaborative frameworks that bring together stakeholders to design collectively the energy systems of the future. Even though, AEMO's ISP is set in a market-based environment, many good practices can be derived for Indonesia's power sector.

Incentives to deploy the needed grid infrastructure

Grid development delays and curtailment are a major risk for investors in renewable resources. A higher level of investment in grids is needed to enable better access to the available resources and to support Indonesia's sustainability objectives. In the meantime, enhanced network management practices such as dynamic line rating (DLR)[27] can be implemented to help maximise the use of the existing grid, defer investments in new assets and reduce congestions when weather conditions are favourable. From 2028 onwards, interconnections with other systems may increase benefits, through sharing reserves and further optimising the use of resources. This was already evidenced by the IEA's study supporting multilateral power trading in ASEAN and is further elaborated in IEA's upcoming Energy Sector Roadmap to Net Zero Emissions in Indonesia. Multi-value approaches help accelerate grid expansion as they account for all benefits of grid projects: increased reliability; sharing existing resources and reducing reserves; and decarbonisation through better use of low-carbon resources.

The creation of renewable energy development zones (REDZ) can also be useful in accelerating the growth of renewables. REDZ are locations with abundant renewable potential which are remote from the existing grid. To harness the potential from these areas in the most cost-effective way, the grid is designed and deployed pro-actively to accommodate many renewable plants.

To accelerate investment in grids, the Indonesian institutions can create an environment to attract private sector capital. Many business models exist for privately-financed transmission as elaborated by the IEA and UN ESCAP. As there is a legal requirement that the Indonesian grid be operated by PLN, two models stand out: the financial ownership model and the BLT model. Regardless of the chosen model, policy and regulatory changes may be needed.

Financial ownership means that a private company provides (part of) the financing for a new transmission line, but that the line is built and operated by the public utility. The investment prospect is provided by the public utility. The private investor receives a return and pays operation costs according to its ownership share. As the revenue is typically linked to the line usage, the main risk is related to the trust in the utility to build and operate the line as planned. This model was

[27] Dynamic line rating (DLR) refers to the active varying of presumed thermal capacity for overhead power lines by taking into account actual operating and ambient conditions instead of assuming a fixed capacity. In particular, colder and windier days allow a higher physical flow than the fixed or seasonal rating.

applied to one cross-border line between Germany and Denmark, where Vattenfall owns a third of the line.

The BLT is an alternative to build, own, operate and transfer (BOOT), which is one of the most used models worldwide. In the BLT model, a private company finances and builds a new transmission line on behalf of the public utility and then leases the project back to the utility for a predetermined period (the concession period – typically 25 years or longer). In this model, the private company assumes the risk to build and commission the line by the contractual deadline.

Consideration of all cost-effective options over the long term, including alternatives to new supply side assets

While new assets are important, policy and regulations must encourage and reward risk-taking towards adoption of innovative, non-capital related solutions, especially when they benefit the end user. Even in growing economies like Indonesia, a significant share of the increasing demand can be met without deploying new power plants. Measures incentivising energy efficiency and smart consumption, and shifting demand away from peak times, will become necessary as new electric load grows. The various options should be compared through a **cost benefit analysis** that takes into account costs and a variety of benefit categories which include reliability and environmental impacts. The ranking of the projects can then be made based on criteria aligned with policy objectives.

Stakeholder engagement and transparency in planning to attract investment in grid-friendly resources

Significant improvements to the processes under PNL's RUPTL are to mandate stakeholder consultations and to make more transparent the allocation of projects approved under the RUPTL.

Planning is essential to assess the system needs and provide signals for investment in the resources. However, planning the system for the next decades is a complex task, as there are many uncertainties such as technologies and their costs, the global environment and the behaviour of consumers. Therefore, planning should ensure robustness with respect to these uncertainties. This can be achieved through the use of stochastic approaches and multiple scenarios complemented with sensitivities with respect to major assumptions. Scenarios should span a large set of possible futures, such as the penetration of distributed resources and technology choices. Major assumptions may include the speed of phasing in/out of technologies (phase-out of coal generation or phase in of new low-carbon technologies) and the cost of capital. As climate adaptation is a growing concern, planning should also consider stress tests with respect to extreme weather events.

Transparency and stakeholders' consultation across the planning cycle bring many benefits. On the one hand, stakeholders can provide inputs to reduce the range of uncertainties and select appropriate scenarios. On the other hand, the sharing of plans provides stakeholders (investors and industrial consumers) with transparent information about the locational value of new resources, supporting deployment at the most efficient locations.

Annex

Abbreviations and acronyms

AEMO	Australian Energy Market Operator
ASEAN	Association of Southeast Asian Nations
BLT	build-lease-transfer
BOOT	Build-own-operate-transfer
BPP	average cost of production (*biaya pokok penyediaan*)
CAPEX	capital expenditure
CF	capacity factor
CCGT	combined-cycle gas turbines;
CCUS	carbon capture, usage and storage
DGE	Directorate General of Electricity (*Direktorat Jenderal Ketenagalistrikan, DJK*)
DMO	Domestic Market Obligation
ETS	emissions trading scheme
EV	electric vehicle
ICE	internal combustion engine
IEA	International Energy Agency
IPP	independent power producer
JVB	Java-Bali (system)
KEN	national energy strategy (*Kebijakan Energi Nasional)*
LCOE	levelised cost of energy
LOLP	loss of load probability
MEMR	Ministry of Energy and Mineral Resources (*Kementerian Energi dan Sumber Daya Mineral*, ESDM)
NDC	Nationally Determined Contribution
NRE	new and renewable energy (*Energi Baru dan Terbarukan*. EBT)
OCGT	open-cycle gas turbine.
O&M	operations and maintenance
OPEX	operational expenditure
PLN	Perusahaan Listrik Negara (State Electricity Company)
PPA	power purchase agreement
PV	photovoltaic
RUEN	National Energy Master Plan (*Rencana Umum Energi Nasional)*
RUKN	National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional*)
RUPTL	Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik)*
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SUM	Sumatra (system)
ToP	take-or-pay

VRE	variable renewable energy
WACC	weighted average cost of capital

Units of measure

bcm	billion cubic metres
Btu	British thermal unit
EJ	exajoules (1 EJ = 23.88 million tonnes oil equivalent)
GW	gigawatt
GWh	gigawatt hour
km	kilometre
kV	kilovolt
kW	kilowatt
mBtu	million British thermal units
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
TWh	terawatt hour

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