Consequence of alternative power plant developments

Power sector scenario study in Indonesia

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Ea Energy Analyses

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Executive summary

The national energy policy (KEN) of Indonesia has long-term targets for the share of coal, gas and RE (renewable energy) in the Indonesian energy system. The official long-term power system plan of Indonesia (RUPTL) is prepared annually by the Indonesian utility company PLN and approved by the DGE, and the RUPTL is currently forecasting a strong growth in power demand, which is to be covered primarily by new coal and gas fired capacity.

The current study analyses the potential consequences associated with the current and proposed power planning policies in Indonesia. The analysis is primarily based on comparing 4 potential scenarios:

- A "Current Policy scenario", which is based on current fuel share targets and electricity demand projections
- A "Lower electricity demand scenario", which is similar to the above, but with lower electricity demand projections
- Two "Least cost development scenarios", which each endeavour to meet electricity demand projections at the lowest possible socioeconomic cost. One places a cost on externalities (i.e. NO_x, SO_2, etc.) while the other does not.

The lower electricity demand projections are based on an analysis of the historic trends in GDP growth and energy intensity development, as well as external studies of the potential for energy efficiency in the power sector. Both analyses find a 20% lower power demand by 2026 than in the projections in PLN's business plan.

Analysing potential power capacity development scenarios with the power system model Balmorel, shows that the power capacity currently categorised as 'under commission' in PLN's business plan is more than sufficient to fulfil electricity demand in the short term. This is highlighted by the fact that the capacity build (of coal in particular), stagnates between 2020 and 2025 in a Current Policy scenario.

With an alternative lower electricity demand projection (20% lower by 2026, and 60% lower in 2050), this finding becomes even more pronounced, as coal capacity peaks in 2020, and decreases until 2030. Historic trends in energy intensity and GDP growth, as well as the potential for energy efficiency improvements, both point towards 20% lower electricity demand in 2026 (separately). Therefore, this alternative demand projection is likely more realistic than the current official Indonesian forecast, and may in fact represent a conservative reduction.

In terms of total cost, the differences between the two demand projections may be enormous. The analysis estimates that the accumulated cost savings of investment, O&M and fuel from now to 2050 associated with cost-efficient energy planning could be *roughly one trillion USD.*

Removing the policy restriction regarding fuel mix, and implanting polices in line with a society least cost scenario (including capital, O&M, fuel and externality costs), yields the same conclusion, i.e. a large risk of under-utilised coal power plants.

The two scenario analyses therefore both indicate a significant risk that power plants will not be able to cover their fixed costs, and thus become stranded assets.

It is therefore recommended to postpone the planned expansion of coal-fired power plants until more analyses can be undertaken.

The analyses regarding the cost of pollution in the Indonesian provinces find that the societal costs are significant. A new super critical coal-fired power plant on Java will negatively impact the society at a level of 4 US cents per kWh, and 2 US cents per kWh if the power plant is commissioned on Kalimantan. The reason for this difference, although both significant values, is mainly due to the population density. Implementing de-NO_x, de-SO_2, and filters to fulfil international standards decrease these costs to 2 US cents per kWh (Java) and 1 US cent per kWh (Kalimantan), which is significantly lower, but due to the additional investment cost of this equipment the clean RE alternatives, such as PV, are more competitive.

Although this pollution has a considerable cost for society, it must first be recognised, and a value must be placed on it. If it is not valuated, taxed or regulated, then PLN or IPP's do not have the economic incentive to decrease their emissions.

It is therefore recommended that the government should acknowledge and implement a cost on pollution in the regulation. This could be done by decreasing the allowed specific pollution of SO_2, NO_x and $PM_{2.5}$ in the already existing minister regulation (Minister of Environment Regulation 21/2008), or by implementing taxes on pollution.

The analyses show that the least cost development will include a significant expansion of RE, especially solar PV, hydro and geothermal.

Several RE technologies are competitive with coal and gas, particularly solar PV. When including all societal costs, both wind and solar RE technologies are highly competitive. **It is therefore recommended that regulation, tax system and grid codes should promote these technologies to capture this socioeconomic benefit.**

1 Introduction

The national energy policy (KEN) of Indonesia has long-term targets for the share of coal, gas and RE (renewable energy) in the Indonesian energy system. These targets are set as primary goals by the Secretary General of the National Energy Council (SG-NEC) and the Director General of Electricity (DGE) in preparation of their respective long-term plans, RUEN and RUKN.

The official long-term power system plan of Indonesia (RUPTL) is prepared annually by the Indonesian utility company PLN and approved by the DGE. The RUPTL is currently forecasting a strong growth in power demand, which is to be covered primarily by new coal and gas fired capacity.

However, studies show that three developments challenge the rationale of the current plans (Ea Energy Analyses, 2017; IEEFA, 2017):

- The considerable potential for electricity savings measures;
- The sharp decrease in the cost of renewable energy technologies, most notably solar PV;
- The societal cost of pollution from SO_2, NO_x and $PM_{2.5}$.

Based on analytical work involving renewable energy technologies, energy efficiency measures, and long-term energy planning undertaken within the Environmental Support Program Phase-3 (ESP3), this report provides a review of Indonesia’s current long-term electricity planning. The work is supported by the Danish International Development Agency (DANIDA) and the Danish Energy Agency (DEA).

2 Methodology

The focus in the current analysis is on the Indonesian power sector in the short and long term (long term in this context is defined as 2050).

2.1 Scenario Setup

In order to analyse the potential impacts of the current Indonesian energy plans and policies on the Indonesian power system, four alternative scenarios were developed and analysed via the Balmorel model.

1. Current Policy

The first scenario is the Current Policy scenario which incorporates the most important official Indonesian policy targets from the country's national energy policy (KEN), national energy plan (RUEN), and nationally determined contributions (NDC) to the Paris climate accord. This scenario resembles the Current Policy scenario in the Indonesian Energy Outlook 2017[1] (IEO17). The scenario contains political targets for fuel mixes, which fix the share of various fuels and thereby only allows the model a small degree of freedom when determining the types of power generation to be invested in.

2. Lower Electricity Demand

The second scenario analyses the consequences and impacts associated with an electricity demand that is lower than the current projections utilised by the Indonesian government. The formulation of the alternative demand projection is explained and discussed in section 3.3.

3. Least Cost Development

The Least Cost Development scenario examines the impact of *not* having fixed political targets for fuel mixes. The development in the scenario is purely determined by the socio-economical costs associated with each of the power generation technologies, i.e. costs related to investment, O&M, fuel and externalities. The various costs and resources are discussed in sections 3.3 and 3.4. In this scenario there is no restriction on the amount of solar PV that can be installed in each province.

4. Least Cost Development w/o cost of pollution

The last scenario is a variant of the above Least Cost Development scenario, but without a cost being placed on local pollution, i.e. health related and premature

[1] The scope of the Indonesian Energy Outlook 2017 is the total energy sector. In the IOE17 two scenarios are analysed; 1) Current Policy and 2) RE & EE Optimization.

mortality related costs. The costs associated with local pollution are discussed in section 3.4.

Scenario preparation

The scenario setup is summarised in Table 1. The scenarios differ according to four elements: 1) Removal of policy targets related to fuel mix, 2) electricity demand projections, 3) restriction on solar potential, and 4) cost of local pollution.

Scenario	Political targets	Demand	Min. fuel share target (2025/2050)	Externality cost of pollution	Solar potential
Current Policy	KEN, RUEN, NDC	RUPTL projection	Coal: 48% Gas: 15% RE: 33%	None	All: 208 GW Java: 33 GW
Lower Electricity Demand	As **Current Policy**	Compared to **Current Policy:** 20% lower by 2025 30% lower by 2030 60% lower by 2050	As **Current Policy**	None	All: 208 GW Java: 33 GW
Least Cost Development	None	RUPTL projection	Free	Externality cost on NOx, SO2 and PM2.5	Free
Least Cost Development w/o cost placed on pollution	None	RUPTL projection	Free	None	Free

Table 1: Scenario setup summary.

2.2 The Balmorel model

The scenarios are developed and analysed utilising the Balmorel model. Balmorel is a detailed techno-economical partial equilibrium model suited for analyses of power systems. It is capable of both capacity expansion and dispatch optimisation.

In investment mode, it is able to simultaneously determine the optimal level of investments, refurbishment and decommissioning of electricity and heat generation and storage technologies, as well as transmission capacity between predefined regions.

In dispatch optimisation mode, it determines the optimal utilisation of available generation and transmission capacity. It is capable of both time aggregated, as well as hourly modelling, which allows for a high level of geographical, technical and temporal detail.

The mathematical principle behind Balmorel is based on finding a least-cost solution for dispatch and investments within the relevant interrelated electricity and district heating markets. Doing so, Balmorel considers developments in electricity and heat demand, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, and spatial and temporal availability of renewable energy.

The modelling setup for the current study has been prepared in close cooperation with the modelling team at the SG National Energy Council. The overall model setup is similar to that of the *Indonesian Energy Outlook 2017*, prepared by the staff of the National Energy Council. There have been small updates since the preparation of the Outlook, primarily related to the continuing work on the technology catalogue, *Technology Data for the Indonesian Power Sector*.

Key input data

Technical and financial data for power generation units are based on the Indonesian National Energy Council's *Technology Data for the Indonesian Power Sector – December 2017*. The discount rate applied is 8% (real terms), and the depreciation time for investments in new power plants is 20 years.

The current power capacity is implemented as an exogenous input. Short-term capacity expansions are also implemented exogenously based on the RUPTL, where all plants listed as 'under commissioning' are implemented – e.g. the coal power expansion until 2020 is locked.

In 2017, there were limited bottlenecks in the Java-Bali system. In Sumatera however, the provinces are connected, but only with medium voltage lines, and as a consequence there are significant bottlenecks in the grid.

Figure 1 illustrates the modelled representation of the current Indonesian electricity transmission system, and the assumed development until 2050. The transmission connections between the provinces are provided by PLN, and the expansion between provinces are from RUPTL 2017-2026. Thereafter, the transmission expansions are projected to develop in accordance with the electricity demand growth projections as in the Current Policy scenario. PLN has provided QA for the projection for the Energy Outlook. The same transmission expansion is assumed in all four scenarios.

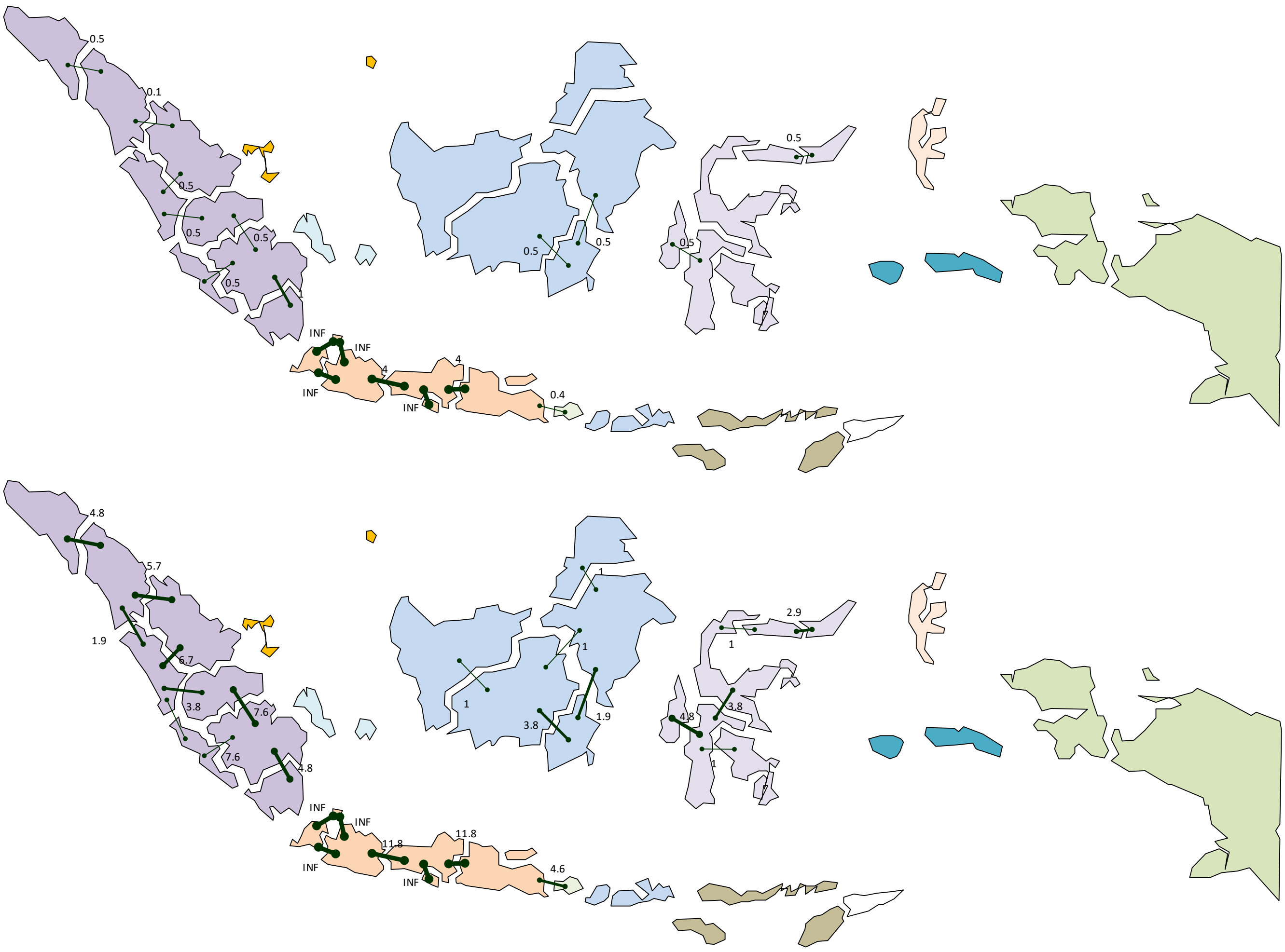

Figure 1: Transmission connections between provinces. Top: 2015. Bottom: 2050.
Note: 'INF' (infinity) implies no assumed transmission capacity constraint between two areas.

3 Scenario preparation

3.1 Policy target for fuel mix

In the Current Policy and Lower Electricity Demand scenarios, the fuel mix is fixed in accordance with the political targets from RUEN for the shares of coal, gas and RE as shown in Figure 2.

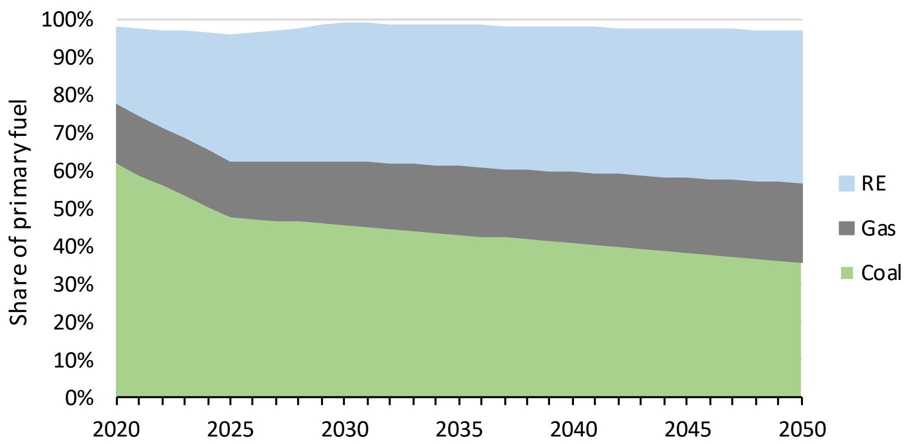

Figure 2: Fuel mix targets from RUEN.

Assumptions on efficiency

The political targets for Indonesian national energy policy (KEN) for fuel mix are stated in terms of primary energy – i.e. share of demand based on fuel consumption. The targets are therefore impacted by the efficiencies of power plants, and the definition of efficiencies for power generation units that do not use fuel – e.g. hydro, wind and solar. The KEN does not directly specify the efficiencies to be applied for renewable energy generators. This analysis relies on the technology fuel efficiencies agreed upon by Indonesian stakeholders in the preparation of the RUEN. For thermal power plants, the specific thermal electric efficiencies applied come from the above-mentioned technology catalogue. Geothermal power plants are assumed to have a 20% efficiency, hydro (both reservoir and run-of-river) a 33% efficiency, and solar PV, wind turbines, and tidal (ocean) power are all assumed to have a 25% efficiency.

3.2 The demand projections

Demand projection in RUPTL

The baseline electricity demand projection used for the Current Policy and Least Cost scenarios is based on PLN's 10-year business plan (RUPTL 2017-2026) for each region. Thereafter, demand is projected in accordance with an annual average real GDP growth of 5.6% (used in the Energy Outlook 2017), and an energy intensity of 1.0 (more on energy intensity rates below). Note that a 10% distribution loss is assumed for all provinces.

Assessment of alternative demand projection

The expected strong growth in power demand is the key driver for the deployment of new power generation capacity in the RUPTL. The plan expects an average increase in power demand of 8.3% over the period 2017-2026, leading to more than a doubling in electricity demand in that period. Economic growth, expressed in GDP, is commonly considered to be the main driver for growing energy demand. In the RUPTL, GDP is projected to grow at an average annual real rate of 6.2%. For comparison, the historic GDP growth since 2001 was 5.3% (simple annual average) and over the last 5 years it has also been 5.3%. Thus, compared to the historic figures, the RUPTL appears to be somewhat optimistic regarding future economic growth.

Power intensity rates, i.e. the relationship between GDP and electricity demand are also in the high range. Historically, power intensities have fluctuated quite a lot from one year to another. The average level has been approx. 1.22 per annum since 2001, with a slightly decreasing trend. The RUPTL expects a power intensity of roughly 1.39-1.55 from 2017 to 2021, with this gradually declining thereafter to around 1.15 by 2026. Compared to a historic trend line projection, the RUTPL projection is somewhat higher, particularly in the beginning of the projection horizon.

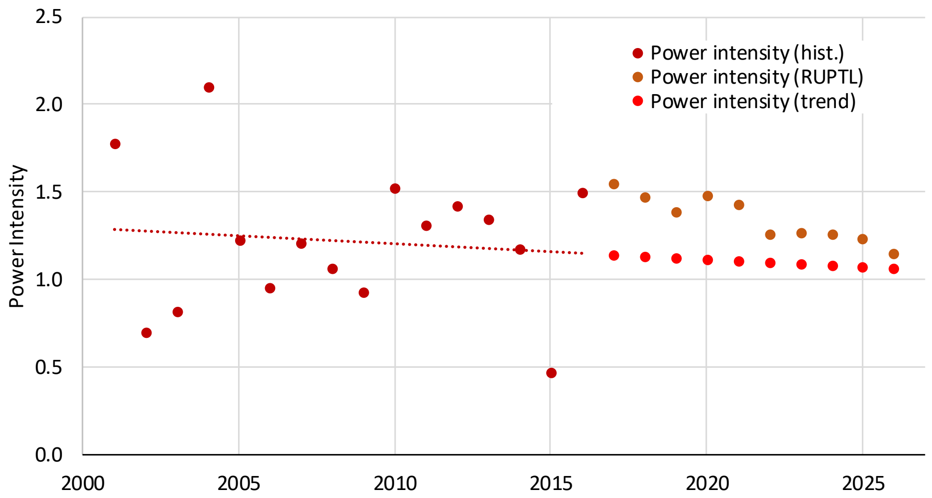

Figure 3: Development in power intensities: historic values, trend line based on historic value and power intensities applied in RUPTL.

Assessment of decrease due to historic trend

When compared to historic figures and extrapolations, both the GDP growth rate and power intensities appear to be somewhat high. If both GDP growth and power intensity rates were adjusted downward to reflect average historic GDP growth rates (5.3%), and the historic trend line for power intensity (as depicted in Figure 3 above), annual electricity demand in 2026 would be almost 20% lower than projected in the RUPTL (see Figure 4).

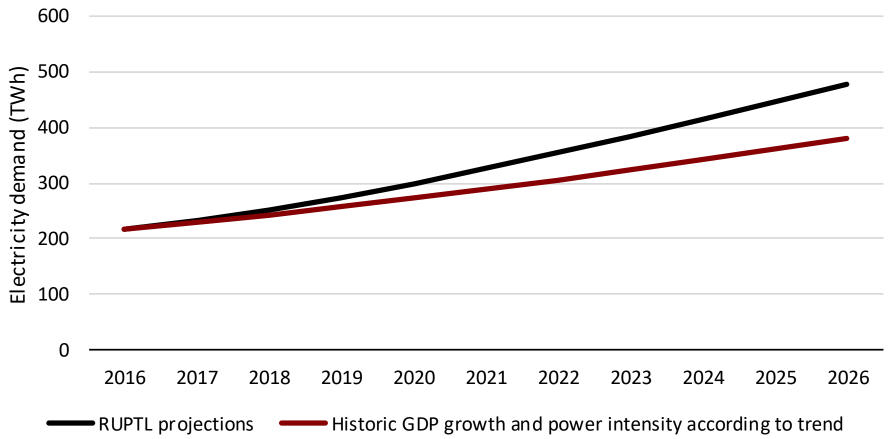

Figure 4: Projection of electricity in Indonesia by RUPTL and with analyses of the historic trends.

In addition, as will be discussed below, there is significant potential to reduce electricity demand in accordance with the national energy efficiency target, which requires a 17% reduction in overall energy demand by 2025.

Energy efficiency and savings

International experiences and studies have shown energy efficiency shall be considered as the “first fuel” – i.e. the cheapest way of satisfying energy demand is using less. Existing studies show that the implementation of energy efficiency policies may significantly curb future electricity demand in Indonesia, as described below.

In April of 2017, the Directorate General of New, Renewable Energy and Energy Conservation (DJ-EBTKE), under the Ministry of Energy and Mineral Resources (ESDM), published the report “Support to Monitoring and Estimation of Energy Conservation Policies Impact”, supported by Environmental Support Program Phase-3 (ESP3) – Danish International Development Agency (DANIDA) and Danish Energy Agency (DEA). The purpose of the study, which was prepared by the Indonesian Institute for Energy Economics (IIEE), was to understand and quantify the impact of energy conservation actions in the household, building, industry, and transportation sectors.

Using the LEAP model[2], final energy demand was projected in three scenarios: Business As Usual (BAU), Market Driven, and Policy Intervention. The BAU scenario represents the reference scenario of the KEN. In this scenario, the average energy intensity is assumed to be the same as its value in the baseline year (2015). The Market Driven scenario assumes that improvement in energy

[2] LEAP, the Long-range Energy Alternatives Planning System, is a widely-used software tool for energy policy analysis and climate change mitigation assessment developed at the Stockholm Environment Institute. (https://www.energycommunity.org/)

intensity is only driven by the economic or market considerations. In the Policy Intervention scenario, the Government of Indonesia implements a series of energy conservation policies to force the market to consume less energy, but while still maintaining the same level of productivity throughout the planning horizon.

The economic growth and activity level within different sub-sectors is assumed to be the same in the three scenarios.

The Policy Intervention scenario considers a broad range of energy efficiency measures, including Minimum Energy Performance Standards and energy labelling of appliances, mandatory energy management in industries with large energy demand, and Mandatory Green Building for new buildings.

In the Policy Intervention scenario, the energy efficiency measures result in an 11% reduction in total final energy demand by 2025 compared to the business as usual scenario. By the 2050, the difference increases to 22%.

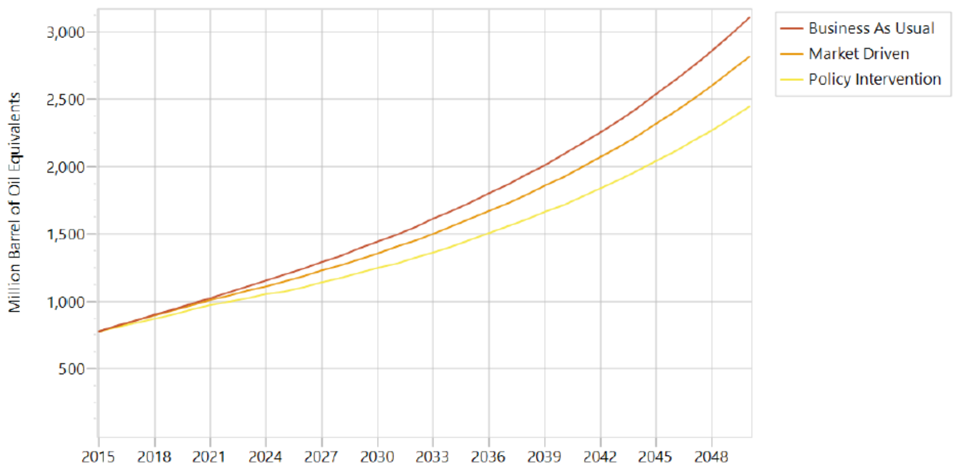

Figure 5: Final Energy Demand for BAU, MD, and PI Scenario (figure from the IIEE report).

The reduction in electricity demand is more pronounced. Figure 6 displays the development in electricity demand in the business as usual scenario and the policy intervention scenario, focusing on the period 2015-2030. By 2026, the demand is 20% lower in Policy Intervention scenario compared to BAU, and this difference increases to 35% by 2050. Specific measures which restrain electricity demand are minimum energy performance standards for air-conditioners, mandatory green building standards for new buildings, and minimum energy performance standards for electric motors in industry.

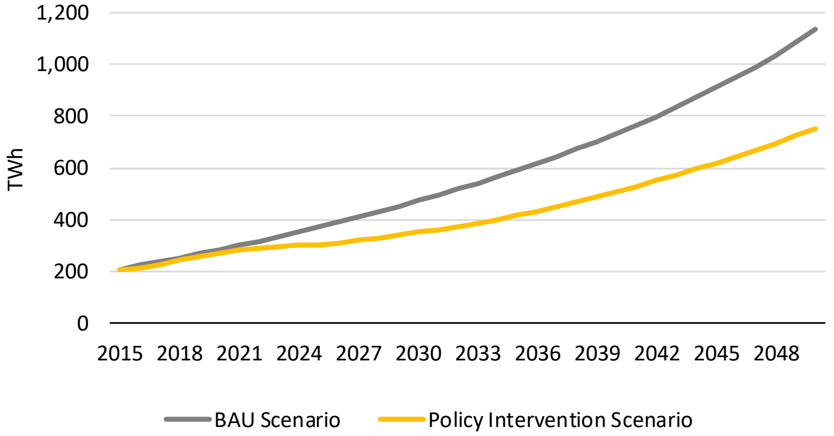

Figure 6: Demand for electricity in the BAU and the PI Scenario for Indonesia.

Assessment of demand in the scenarios

The two findings above, regarding both historic trends and energy efficiency potentials, highlight the relevance of analysing a scenario with a lower electricity demand than projected by the RUPTL. This electricity demand for the Low Demand scenario captures the energy efficiency potential, the decrease in energy intensity, the lower projected GDP growth. In the long-term it also captures the decoupling of GDP growth and power demand. Compared to the RUPTL electricity demand projection, the demand in this scenario is 20% lower by 2025, 30% lower by 2030 and 60% lower by 2050. This can be considered a conservative projection, since both the EE and historic trend yield 20% lower demand in 2025. The electricity demand in the present study's four scenarios is shown in Figure 7.

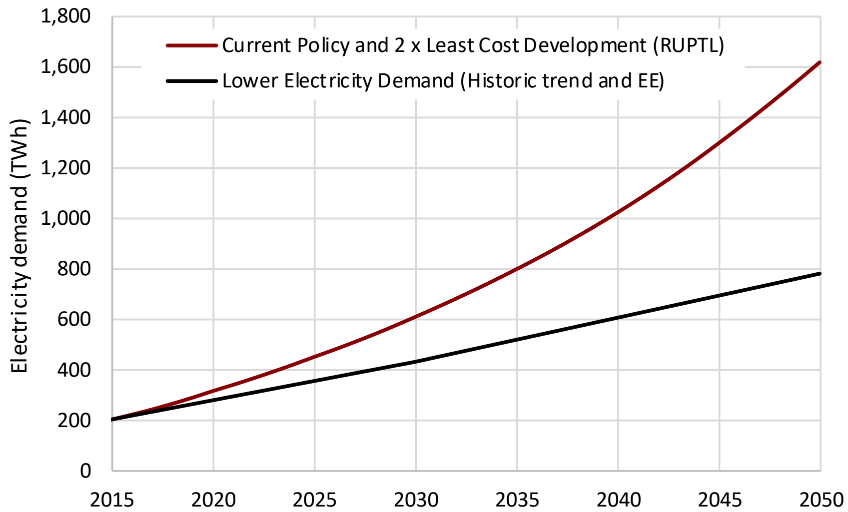

Figure 7: Demand projections in the four scenarios.

Demand of electricity by province

There are significant differences in electricity demand growth between the provinces. The demand per province is specified in accordance with PLN's business plan, RUPTL 2017-2026. In 2016, Java accounted for 72% of total electricity demand – a number that by 2026 is expected to decrease to 65% (RUPTL). The share after 2026 is maintained at the 2026 level. The electricity demand by province in the Current Policy and Least Cost scenarios is displayed in Figure 8.

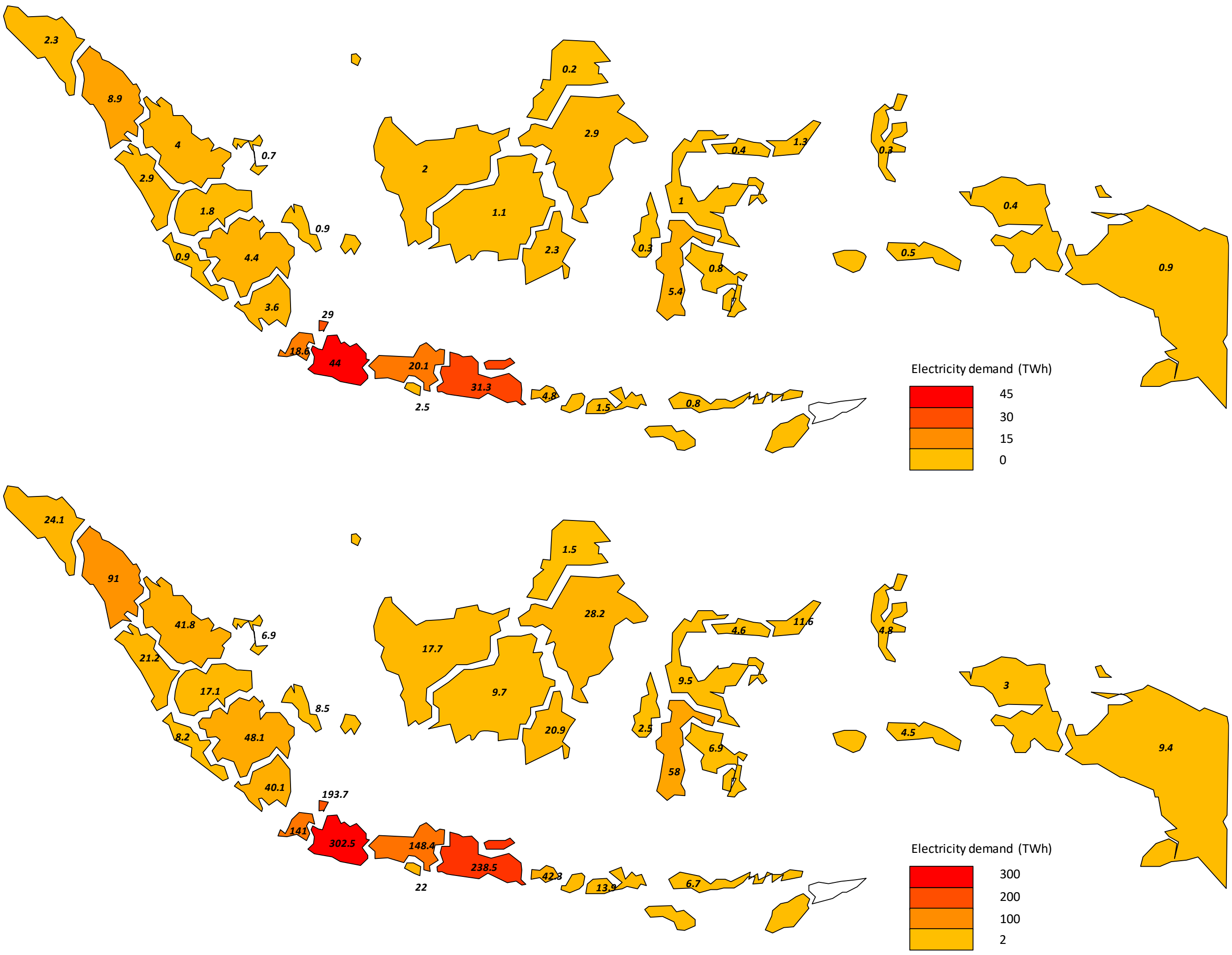

Figure 8: Electricity demand by province in the Current Policy and the two Least Cost Development scenarios. Top: 2015 (203 TWh). Bottom: 2050 (1,616 TWh).

3.3 Solar power resources

RE sources, such as solar and wind, are highly dependent on location. When analysing the resources, the capacity factor for solar and wind is often simplified such that average values are used for geographical areas in combination with a capacity limit for each area – i.e. a maximum MW limit on PV. For the Indonesian setup used in the Energy Outlook, and the current analyses, a more detailed way of capturing the solar potentials has been developed.

The purpose is to capture the geographical differences in solar resources within a province. Unsurprisingly, geographically large provinces will have more significant differences in the quality of its resources than smaller provinces.

The provinces have therefore been split into groups of large, medium, and small geographical sizes. A standard deviation was found for each group, and this, together with an average capacity factor for each province, was then used to generate a normal distribution of the capacity factor for each province. Both standard deviations and capacity factors were found using the interactive map on www.renewables.ninja.

In Balmorel, four artificial subareas were created: *Very Low PV*, *Low PV*, *High PV* and *Very High PV*. The normal distribution from above was then split into four, each representing an equal probability mass. The average capacity factor of each artificial area was found by weighting the capacity factor of each split by the probability. The potential for solar PV for each province in MW from EBTKE was thus subdivide into four equal proportions, which where each associated with one of the capacity factors found.

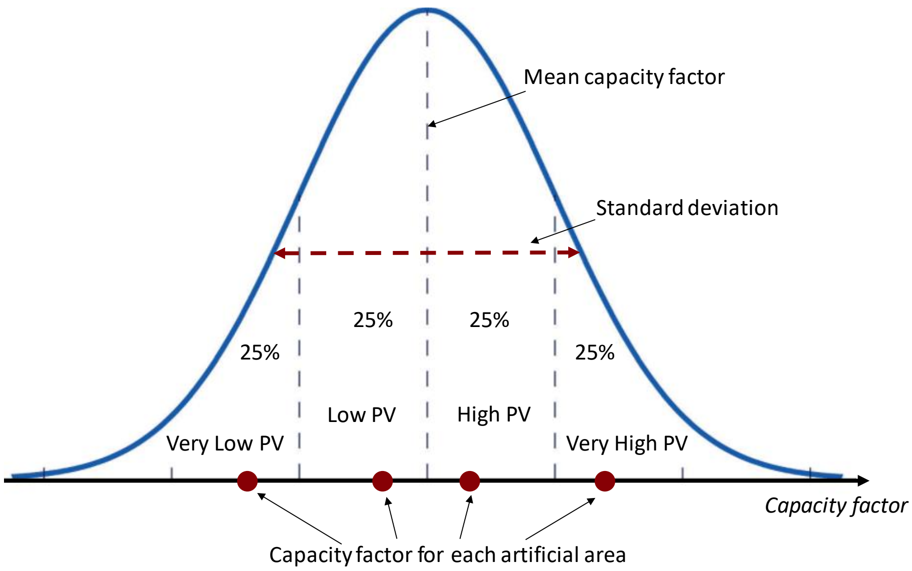

Figure 9: Conceptual illustration of the normal distribution of the solar potential within each province.

The full list of potentials and capacity factors by provinces is shown in the appendix.

Solar power restrictions

The solar potentials utilised are from EBTKE and were used in RUEN and the Energy Outlook. According to this study, Java has a potential of 32 GW. This potential corresponds to only 0.2% of the total area being covered by PV panels. For comparison, Germany today has 41 GW of PV installed, covering approximately 0.2% of the country's area. According to a new report from Fraunhofer, this number can easily by 10 times higher (Wirth, 2017). Therefore, it is considered relevant to analyse the two Least Cost scenarios without a solar restriction (and subsequently calculate the area required). This is done by removing the maximum restriction in the artificial *Very Low* area in Balmorel – i.e. the additional solar PV commissioned will therefore have a lower capacity factor than the average of the potential in the Current Policy scenario.

3.4 External costs of emissions by province

Combustion of fuels such as coal, oil and gas lead to emissions of SO_2, NO_x, and $PM_{2.5}$ which have a considerable impact on human health, causing premature death and illness. In the Least Cost Development scenario these costs are considered as part of the overall societal cost of power generation.

Calculating these impacts, and the cost for society, requires comprehensive and complex atmospheric modelling – such as EVA (Economic Valuation of Air pollution). The EVA model system uses the impact-pathway chain to assess the health impacts and health-related economic externalities of air pollution resulting from specific emission sources or sectors (Brandt et al., 2017). Such a study has not yet been made specifically for Indonesia. Therefore, the costs of pollution in provinces of Indonesia are estimated by comparing them to a similar study of Europe (Brandt et al., 2010). The cost from this study is in euro per kg of pollution of SO_2, NO_x and $PM_{2.5}$ from power plants located in each of the 27 EU countries. The cost is related to the pollution from the specific country, whereas the impact from the pollution can also be felt in neighboring countries. There is a correlation between pollution cost and population density in the surrounding area. Hence, the first step is to compare the cost associated with each country with the population a certain distance from the country – i.e. not the country's own population. To simplify this, a constant distance of 500 km from each country's geographic center is applied to determine the population exposed to the pollution. This comparison is displayed in Figure 10.

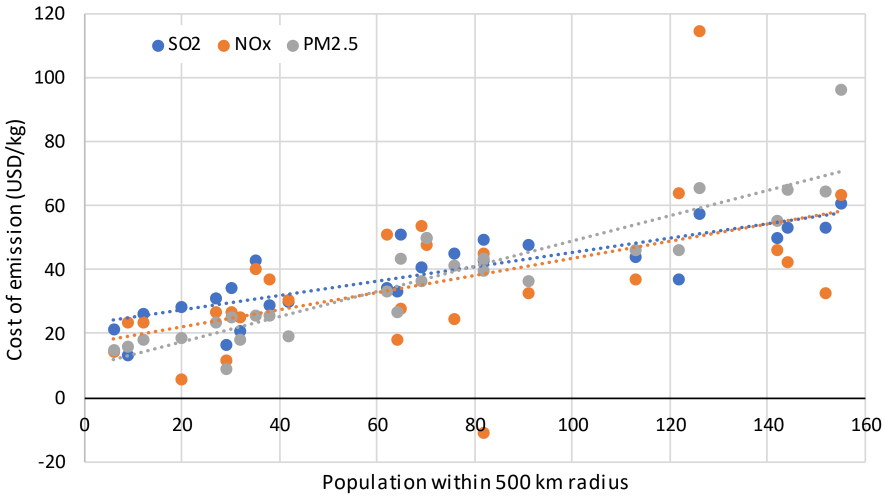

Figure 10: Correlation between the cost of pollution from SO_2, NO_x and $PM_{2.5}$ from each of the 27 EU members and the population within a 500-km radius from the country's geographical centre point.

The figure confirms that pollution costs are highest in the most densely populated areas. This trend is used in the Indonesian context, where the population density is mapped within 500 km of each province's geographical centre. The European costs are applied to Indonesia according to purchasing power parity (PPP), i.e. the purchasing power in Indonesia is 5.3 times lower than the average EU country (World Bank).

The estimated externality costs from power plant pollution are displayed in Table 2. There are considerable geographical differences for SO_2, ranging from almost 10 USD/kg in Central Java, to less than 4.5 USD/kg in North Maluku (see Figure 11).

Figure 11: Externality cost on emitting SO_2 in each province.

Province	SO_2 cost USD/kg	NO_x cost USD/kg	$PM_{2.5}$ cost USD/kg
Aceh	5.3	4.4	3.6
Bali	6.6	5.8	5.8
Bangka-Belitung	7.0	6.3	6.5
Banten	8.4	8.0	9.0
Bengkulu	5.4	4.5	3.8
Central Java	9.8	9.6	11.4
Central Kalimantan	4.8	3.8	2.7
Central Sulawesi	5.0	4.0	3.0
East Java	8.0	7.5	8.2
East Kalimantan	4.7	3.7	2.6
East Nusa Tenggara	5.2	4.3	3.5
Gorontalo	4.5	3.5	2.3
Jakarta	8.9	8.5	9.8
Jambi	5.9	5.1	4.7
Lampung	7.5	6.9	7.4
Maluku	4.3	3.2	1.9
North Kalimantan	4.6	3.5	2.4
North Maluku	4.4	3.3	2.1
North Sulawesi	4.5	3.4	2.1
North Sumatra	6.0	5.2	4.8
Papua	4.4	3.3	2.0
Riau	6.3	5.5	5.3
Riau Islands	5.4	4.5	3.8
South East Sulawesi	4.8	3.8	2.8
South Kalimantan	4.7	3.7	2.6
South Sulawesi	4.9	3.9	2.9
South Sumatra	6.8	6.2	6.3
West Java	8.9	8.6	9.9
West Kalimantan	4.6	3.5	2.4
West Nusa Tenggara	4.8	3.8	2.8
West Papua	4.3	3.2	1.9
West Sulawesi	5.0	4.0	3.1
West Sumatra	6.1	5.3	4.9
Yogyakarta	9.7	9.5	11.2

Table 2: External costs in each province from emissions of SO_2, NO_x, and $PM_{2.5}$ from power plants.

These levels can be considered conservative in the long run in light of considerable rate of economic growth in the scenarios. Economic valuation of health costs is linked to the *willingness-to-pay* for better health outcomes. This willingness-to-pay in general increases with growing affluence in society.

Power plant filters, de-NO_x and de-SO_2

All new power plants are assumed to comply with the current ministerial regulation in Indonesia (Minister of Environment Regulation 21/2008), specifying maximum specific emission of NO_x, SO_2 and $PM_{2.5}$. The coal and gas fired power plants have the additional option of installing flue gas de-NO_x and de-SO_2 systems, and filters for $PM_{2.5}$. The total cost of installing these systems and filters is estimated to be USD 530,000 per MW – and will reduce the emissions of SO_2 by 30%, NO_x by 24% and PM $_{2.5}$ by 90%.

4 Consequence analysis of scenarios

4.1 Current Policy

In the Current Policy scenario, the fuel mix is fixed to the political targets for the share of coal, gas and RE. There is only little degree of freedom for optimization, and therefore it is the competition between technologies within each share that is interesting – e.g. subcritical vs. supercritical coal, and solar PV vs. wind turbines.

Figure 12 shows the development in power capacity and generation in the scenario. Geothermal, hydro and solar power provide the lion's share of RE generation.

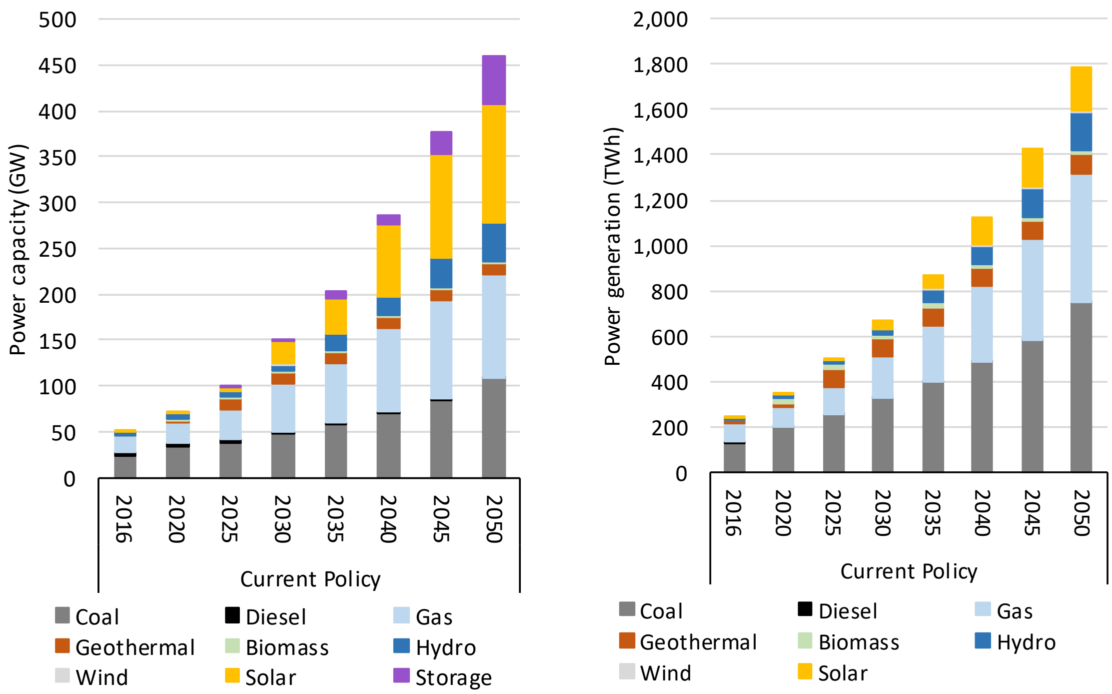

Figure 12: Development of power capacity (left) and power generation (right) by fuel.

Batteries (storage) play a notable role in the system, supplying the evening peak when the sun has set, as can be seen in Figure 13.

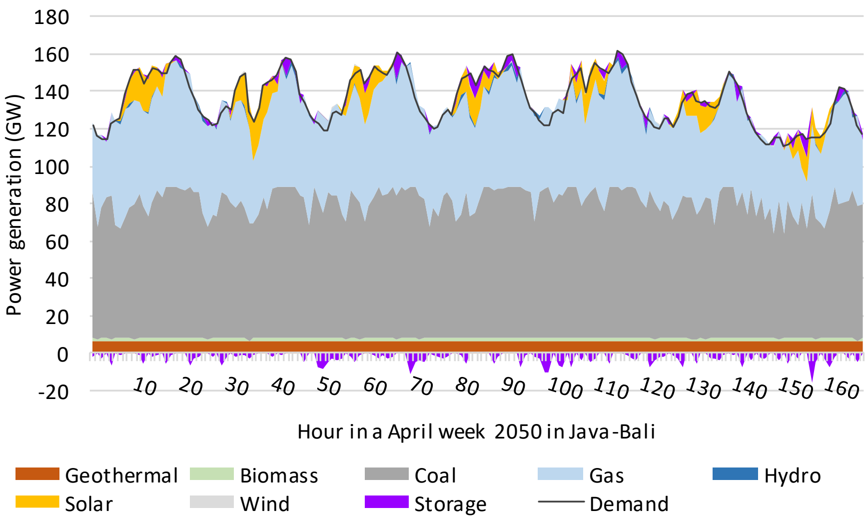

Figure 13: Power generation dispatch in Java-Bali in 2050 on a week in April in the Current Policy scenario.

4.2 Impact of lower electricity demand projection

The lower projected electricity demand in this scenario (see Figure 7) has a significant impact on the required power capacity in the system. The coal capacity increases by 2% annually in this scenario, compared to 5% in the Current Policy projections.

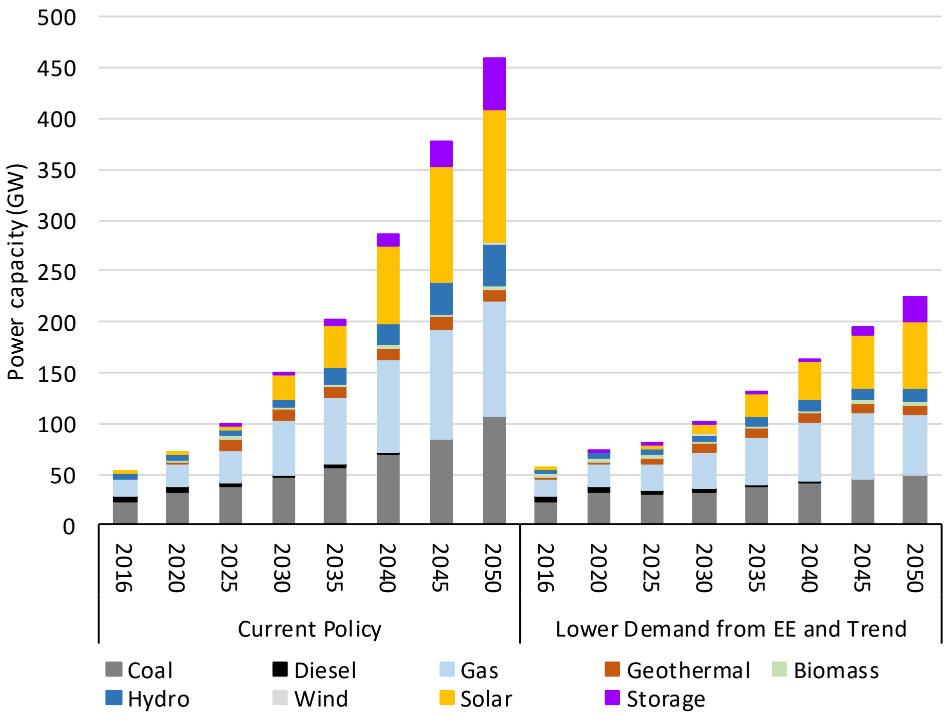

Figure 14: Power capacity development in the Current Policy and Lower Electricity Demand scenarios.

Coal power development

The slower coal build-out has considerable impact, also in the short-term. In the model setup, the exogenous expansion in the short-term is from the RUPTL, where all plants listed as 'under commissioning' are implemented, i.e. coal power expansion until 2020 is *locked in*. The effects of relaxing this constraint are quite evident when looking at the coal expansion in the Java-Bali system (see Figure 15), as both in the Current Policy and the Lower Demand scenarios, the coal capacity peaks in 2020, and the development either stagnates or decreases until 2025. This indicates an overcapacity of coal power in the short-term. In the Lower Demand scenario, the coal power capacity should be maintained at the current level until 2030.

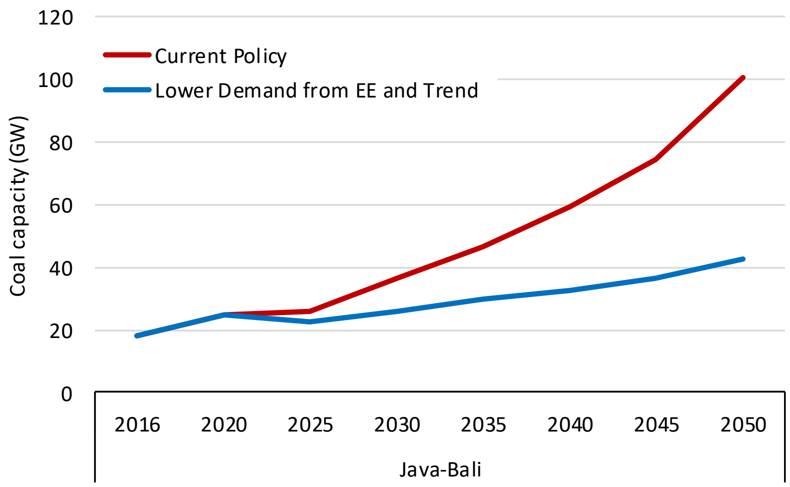

Figure 15: Development of coal-fired power capacity in the Current Policy and Lower Demand scenarios.

Cost savings

There are significant cost savings associated with planning and executing a Lower Electricity Demand scenario (see Figure 16).

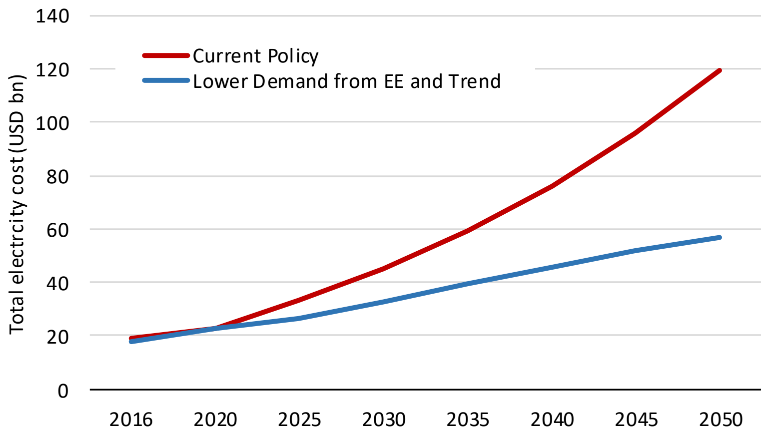

Figure 16: Total cost of electricity in billions of USD in the Current Policy and Lower Demand scenarios (not including societal cost of pollution)

Accumulated over the 34-year horizon, the Lower Demand scenario is roughly *one trillion USD* less expensive than the Current Policy scenario in terms of power development cost, i.e. capital, O&M and fuel costs.

CO_2 emission in Current Policy and Lower Demand

The CO_2 emissions are also reduced with the lower electricity demand. As depicted in Figure 17, the accumulated reduction in CO_2 emission is 1,200 Mtons by 2050. Emissions follow the same path until 2020, since the capacity development is guided by the RUPTL development until 2020.

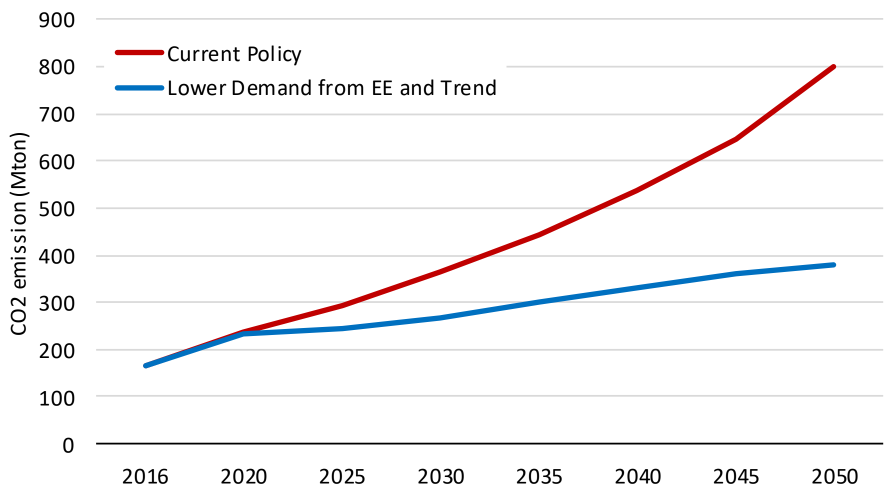

Figure 17: Development of CO_2 emissions in the Current Policy and Lower Electricity Demand scenarios.

4.3 Least Cost Development

The Least Cost Development is optimised to minimise costs related to investment, O&M, fuel and externalities. Compared to the Current Policy scenario, it is not required to comply with a pre-set fuel mix of generation.

Solar expansion

In this scenario, the solar expansion is substantial and covers roughly 25% of electricity demand by 2030, with this share growing to more than 50% by 2050 (see Figure 18). The maximum solar potential in Java-Bali is 33 GW in the Current Policy scenario, which is already utilised by 2040. In the Least Cost scenario, it reaches 33 GW already before 2025, and because there is no restriction on solar in this scenario, it increases to a staggering 550 GW by 2050. This implies that 3.5 % of the surface area on Java and Bali be covered by PV in 2050.

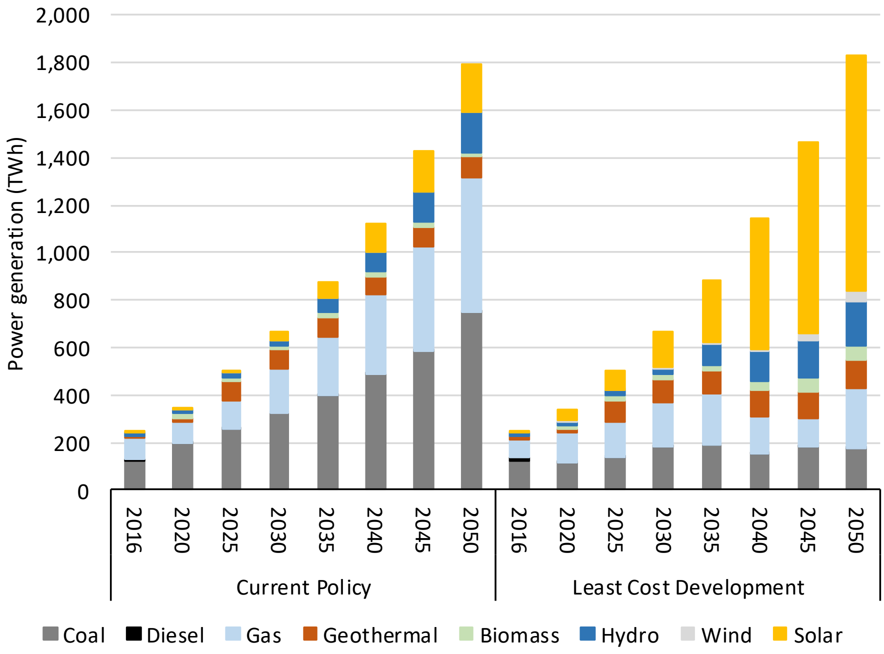

Figure 18: Development of power generation in the Current Policy and Least Cost scenario.

Stagnation of coal consumption

Compared to the Current Policy scenario, the Least Cost Development scenario will drastically decrease the generation from coal-fired plants, as seen in Figure 18. The power generation from coal is kept at the same level as in 2016, thus consuming roughly 70 million tonnes of coal annually.

Risk of stranded assets

Because there is an expected expansion of coal-fired power plants from the RUPTL until 2020, some of these plants will be under-utilised in this scenario. The least cost development scenario sees the economy associated with the new coal plants being significantly diminished.

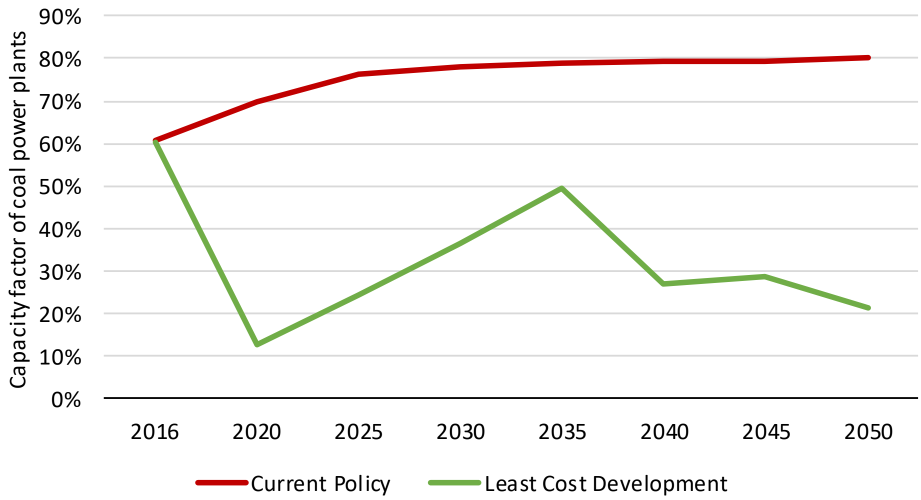

Figure 19: Capacity factor of coal-fired power plants in the Current Policy and Least Cost scenarios in the Java-Bali system.

As displayed in Figure 19, the capacity factor of the coal-fired power plants in Java-Bali will be drastically reduced, especially in the short term. Between 2020 and 2035 the over capacity is gradually reduced as demand catches up. However, from 2035 and onwards renewables are deployed on a least-cost basis to displace operational costs of coal-fired generation, leading again to a reduction in the capacity factors of coal plants.

Short term development

Figure 20 and Figure 21 support this finding showing that the short-term development of coal power capacity is almost identical in the two scenarios (Figure 20), due to the fixed development from the RUPTL. These power plants will however not be utilised much, as can be seen from Figure 21.

Establishing these power plants should therefore be reconsidered, or alternatively, if this is not possible, be installed with significantly better filters and flue gas cleaning systems than the current regulation requires, to improve their competitiveness on a total cost basis.

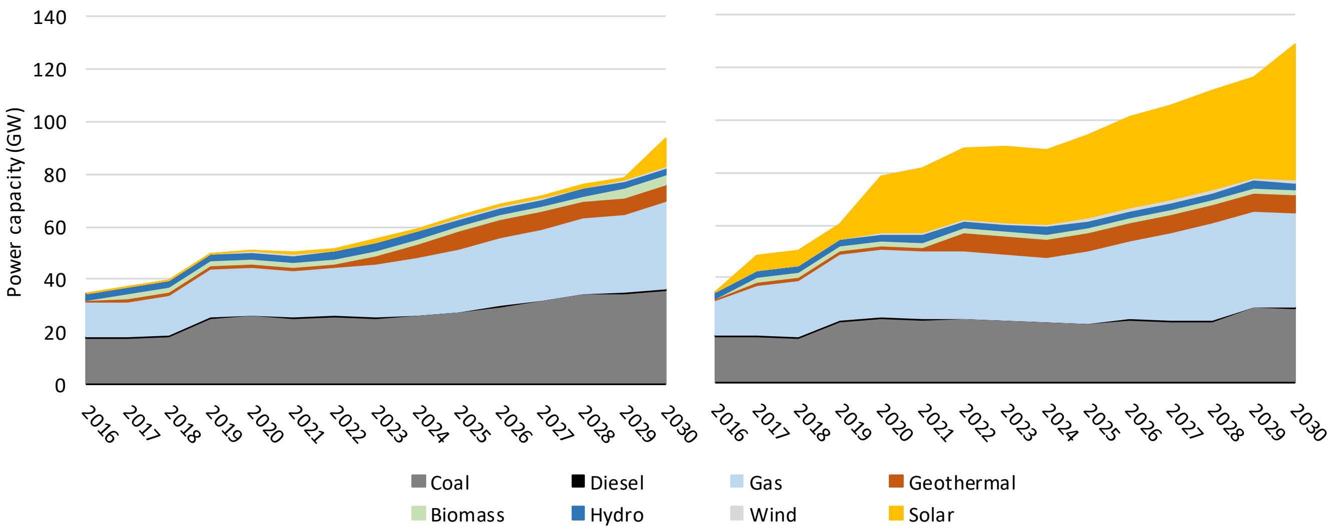

Figure 20: Short-term development of power capacity in Java-Bali in the Current Policy (left) and Least Cost (right) scenarios.

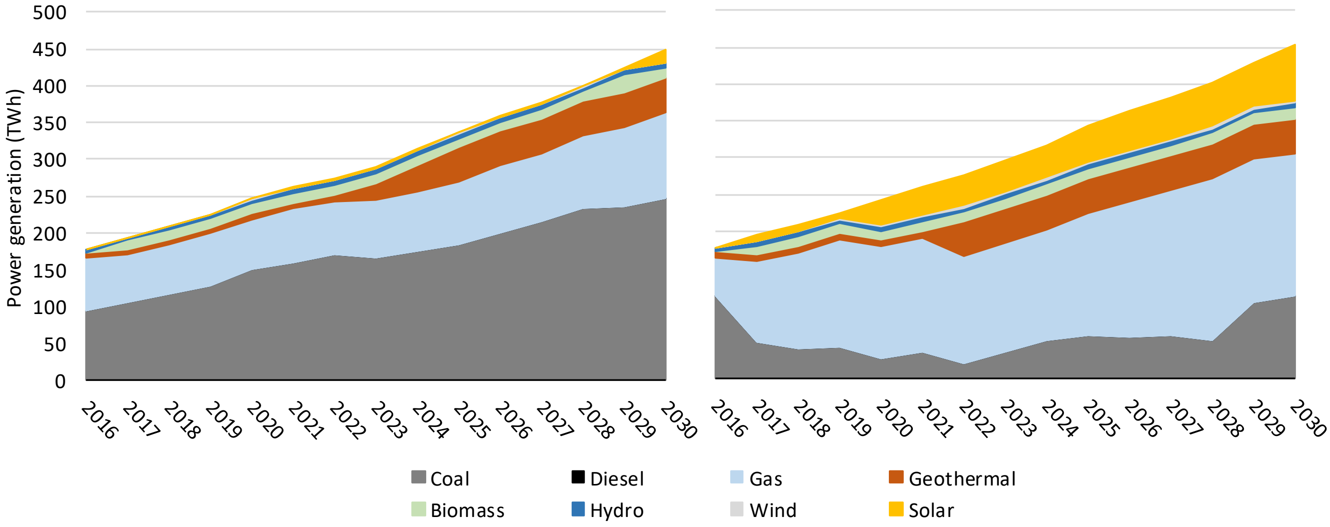

Figure 21: Short-term development of power generation in Java-Bali in the Current Policy (left) and Least Cost (right) scenarios.

4.4 Impact of recognising the externality cost of pollution

As explained earlier in section 3.4, the cost associated with pollution from NO_x, SO_2 and $PM_{2.5}$ relating to human health and premature death is significant. This is a considerable cost for society, but if it is not taxed or regulated, then PLN or IPP's do not have an economic incentive to decrease their emissions. When comparing a scenario where pollution is unregulated, coal power expands and displaces power generation from natural gas, on the basis of raw costs.

CO_2 emissions

The RE technologies, particularly solar PV, is however rather competitive, so even though coal displaces most of the power generation from gas, RE also displaces some of the gas share compared to the Current Policy scenario. Thus, the Current Policy scenario and the Least Cost w/o cost of pollution scenario end up with similar CO_2 emissions (Figure 23). The scenario with the lowest CO_2 emission and is the Least Cost scenario. The accumulated reduction in CO_2 emissions when comparing the Least Cost and the Current Policy scenarios is almost 9,000 Mton.

Total societal cost

The total societal cost of the power system is displayed in Figure 24. The reduced societal cost in the Least Cost scenario compared to the Current Policy is an accumulated 370 billion USD by 2050.

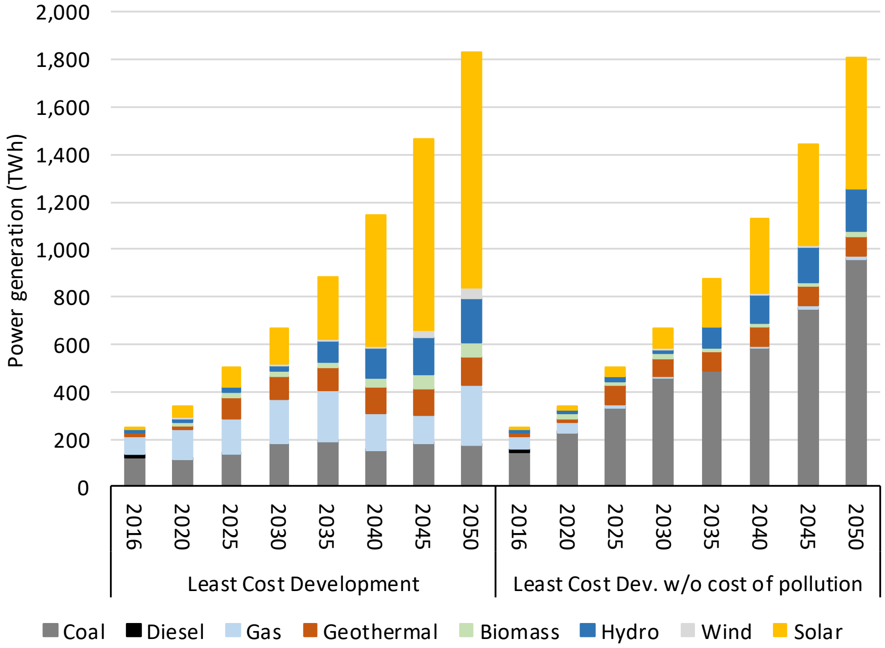

Figure 22: Development of power generation in the Least Cost scenario compared to a scenario where the cost of polluting is not considered.

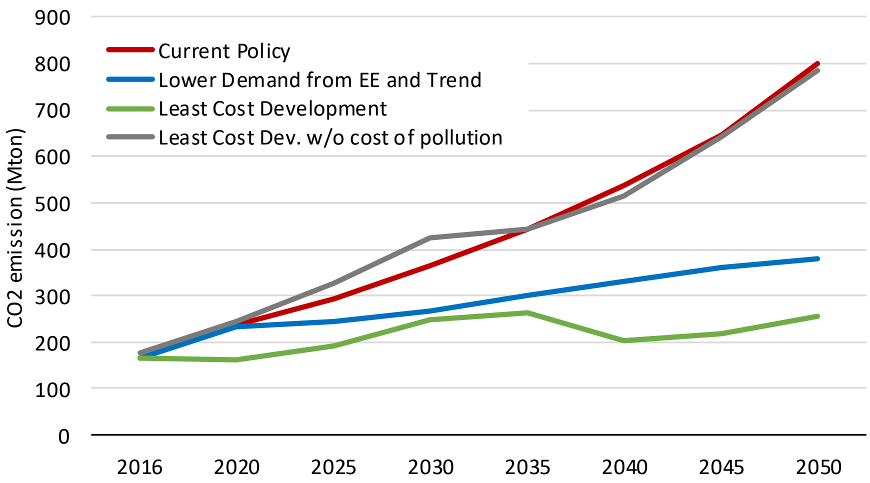

Figure 23: CO_2 emissions in all four scenarios.

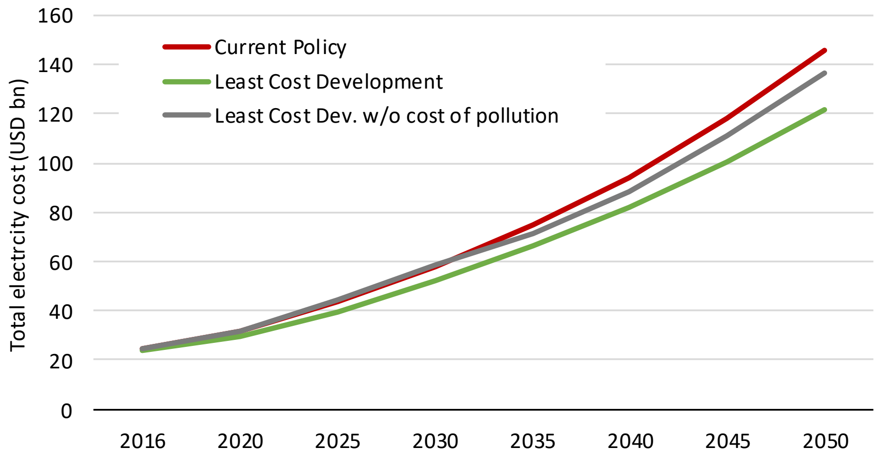

Figure 24: Development in total societal cost of the power system, including investment, fuel, O&M and cost of local pollution.

5 Conclusion and recommendations

The analyses show that the power capacity currently categorised as ‘under commission’ in PLN’s business plan is more than sufficient to fulfil electricity demand in the short term. This is highlighted by the fact that the capacity build (of coal in particular), stagnates between 2020 and 2025 in a Current Policy scenario. With a more moderate electricity demand projection, this finding becomes even more pronounced, as coal capacity peaks in 2020, and decreases until 2030. Considering the historic trends in energy intensity and GDP growth, as well as the potential for energy efficiency improvements, this moderate demand projection is likely more realistic.

The accumulated cost savings associated with planning correctly could be roughly one trillion USD from now to 2050.

Removing the policy restriction regarding fuel mix, and implanting polices in line with a society least cost scenario (including capital, O&M, fuel and externality costs), yields the same conclusion, i.e. a large risk of under-utilised coal power plants.

The two scenario analyses therefore both suggest a significant risk of under-utilised stranded assets – i.e. power plants that cannot cover their fixed costs.

Postpone the planned coal expansion

It is therefore recommended to postpone the planned expansion of coal-fired power plants pending deeper analysis.

The analyses regarding the cost of pollution in the Indonesian provinces find that the societal costs are significant. A new super critical coal-fired power plant on Java will negatively impact the society at a rate of 4 US cents per kWh, and 2 US cents per kWh if the power plant is commissioned on Kalimantan. The reason for this difference, although both significant values, is mainly due to the population density. Implementing de-NO_x, de-SO_2, and filters to fulfil international standards decrease these costs to 2 US cents per kWh (Java) and 1 US cent per kWh (Kalimantan), which is significantly lower, but due to the additional investment cost of this equipment the clean RE alternatives, such as PV, are more competitive.

Although this pollution has a considerable cost for society, it must first be recognised, and a value must be placed on it. If it is not valuated, taxed or regulated, then PLN or IPP's do not have the economic incentive to decrease their pollution discharge.

Acknowledge and implement a cost on pollution

It is therefore recommended that the government should acknowledge and implement a cost on pollution in the regulation. This could be done by decreasing the allowed specific pollution of SO_2, NO_x and $PM_{2.5}$ in the already existing minister regulation (Minister of Environment Regulation 21/2008), or by implementing taxes on pollution.

The analyses show that the least cost development will include a significant expansion of RE, especially solar PV, hydro and geothermal.

Promote RE technologies

Several RE technologies are competitive with coal and gas, particularly solar PV. When including all societal costs, both wind and solar RE technologies are highly competitive. The regulation, tax system and grid codes should therefore promote these technologies to capture this socioeconomic benefit

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Appendix: Solar PV resource

	Capacity factor (%)				Potential (MW)			
	Very Low	Low	High	Very High	Very Low	Low	High	Very High
Bali	18.6%	18.9%	19.2%	19.5%	313	313	313	313
Bangka-Belitung	16.9%	17.2%	17.4%	17.7%	701	701	701	701
Banten	16.9%	17.2%	17.4%	17.7%	614	614	614	614
Central Java	16.4%	17.1%	17.5%	18.2%	2183	2183	2183	2183
East Java	16.4%	17.1%	17.5%	18.2%	2577	2577	2577	2577
Jakarta	16.9%	17.2%	17.4%	17.7%	56	56	56	56
West Java	16.4%	17.1%	17.5%	18.2%	2269	2269	2269	2269
Yogyakarta	16.9%	17.2%	17.4%	17.7%	248	248	248	248
Central Kalimantan	16.0%	17.0%	17.7%	18.6%	2110	2110	2110	2110
East Kalimantan	16.0%	17.0%	17.7%	18.6%	3362	3362	3362	3362
North Kalimantan	16.4%	17.1%	17.5%	18.2%	1158	1158	1158	1158
South Kalimantan	16.4%	17.1%	17.5%	18.2%	1504	1504	1504	1504
West Kalimantan	16.0%	17.0%	17.7%	18.6%	5016	5016	5016	5016
Maluku	18.2%	18.8%	19.3%	19.9%	504	504	504	504
North Maluku	18.2%	18.8%	19.3%	19.9%	757	757	757	757
West Nusa Tenggara	18.2%	18.8%	19.3%	19.9%	2477	2477	2477	2477
East Nusa Tenggara	18.6%	18.9%	19.2%	19.5%	1814	1814	1814	1814
Papua	17.2%	18.1%	18.8%	19.8%	508	508	508	508
West Papua	17.2%	18.1%	18.8%	19.8%	1573	1573	1573	1573
Riau Islands	16.4%	17.1%	17.5%	18.2%	1936	1936	1936	1936
Central Sulawesi	17.0%	17.7%	18.1%	18.7%	1543	1543	1543	1543
Gorontalo	17.4%	17.8%	18.0%	18.3%	304	304	304	304
North Sulawesi	17.4%	17.8%	18.0%	18.3%	527	527	527	527
South Sulawesi	17.0%	17.7%	18.1%	18.7%	1892	1892	1892	1892
South East Sulawesi	17.0%	17.7%	18.1%	18.7%	977	977	977	977
West Sulawesi	17.4%	17.8%	18.0%	18.3%	418	418	418	418
Aceh	16.4%	17.1%	17.5%	18.2%	1965	1965	1965	1965
Bengkulu	15.7%	16.0%	16.3%	16.6%	867	867	867	867
Jambi	15.3%	15.9%	16.4%	17.0%	2206	2206	2206	2206
Lampung	15.3%	15.9%	16.4%	17.0%	558	558	558	558
North Sumatra	15.3%	15.9%	16.4%	17.0%	2956	2956	2956	2956
Riau	14.1%	14.8%	15.2%	15.9%	188	188	188	188
South Sumatra	16.0%	17.0%	17.7%	18.6%	4298	4298	4298	4298
West Sumatra	16.4%	17.1%	17.5%	18.2%	1471	1471	1471	1471