How different electricity pricing systems affect the energy trilemma: Assessing Indonesia's electricity market transition

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The Cost of No Reform: Assessing the Impact of Different Electricity Pricing Regimes on Indonesia's Energy Trilemma

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Abstract:

Many countries have a clear policy objective of increasing their share of renewable energy sources (RES). However, a major impediment for higher RES penetration often lies in historically grown structures of a country's electricity sector. In Indonesia, policymakers have relied on cheap fossil fuels and state control to provide the population with access to both reliable and affordable electricity. However, this focus on only two of the three horns of the energy trilemma, namely, energy security and energy equity (and not sustainability), may put Indonesia at risk of missing its ambitious RES targets. In this context, a number of small-scale reform attempts to promote RES integration in recent years have proved relatively unsuccessful. Like many others, Indonesia needs clear policy directions to avoid an unsustainable lock-in into a fossil fuel future. In the last decades, several other countries have successfully restructured their electricity sectors, e.g., by introducing a wholesale market for electricity under different electricity pricing regimes including nodal, zonal, or uniform pricing. These countries may hold valuable experiences of how to overcome the historically grown barriers to a successful RES integration through a greater role for market mechanisms. This paper develops three generic models that allow policymakers to analyze the impact of introducing either a nodal, a zonal, or a uniform pricing regime on the three horns of the energy trilemma in their country. We evaluate our model using a simplified network representation of the Indonesian electricity sector. Our results indicate that each of the pricing regimes is able to foster specific horns of the energy trilemma. Considering that any major reform intended to improve energy sustainability in Indonesia will only be a success if it also addresses energy security and energy equity, we also discuss our results from the perspective of energy justice and the need to balance the country's energy trilemma. Ultimately, we illustrate a transformation pathway for a more sustainable and just transition to a low-carbon economy in Indonesia.

JEL Classification: Q400, Q410, Q420, Q480, L510, L110

Keywords: Electricity Pricing Regime; Electricity Market Liberalization; Energy Trilemma; Indonesia; Energy Justice; Renewable Energy Sources

1 Introduction

In many countries all around the world measures are being implemented to increase the share of renewable energy sources (RES). Historically, the focus of policymakers was primarily on achieving the first two horns of the energy trilemma, namely, energy security and energy equity (Heffron et al., 2018). In particular, during the first wave of global electricity market restructurings[1] that began in Chile, England and Wales, and Norway in the mid-1980s (Hogan, 2002), policymakers aimed at improving both the operational and economic efficiency of their energy systems (Conejo and Sioshansi, 2018). Corresponding reforms were intended to improve the ability of the energy system to provide electricity reliably (referring to energy security) and at low costs (referring to energy equity) to consumers. Because fossil fuel-based power plants were generally viewed as being more reliable and cost-efficient than RES, project developers have primarily invested in conventional generation capacity.

Today, as the negative consequences of fossil fuel-based electricity generation increasingly become apparent in many countries, policymakers around the world are introducing new reforms to transform their energy systems from high-carbon into low-carbon systems; in particular, policymakers aim to replace conventional power plants with RES. More so than the first wave of reforms of electricity systems, these new reforms will be accelerated by international efforts such as the United Nation's Sustainable Development Goals (SDGs) or the 2015 Paris Agreement – putting additional external pressure on energy policymakers to transform their energy systems into more sustainable systems. Here, it becomes increasingly apparent that the past improvements in energy security and energy equity came at the expense of the third horn of the energy trilemma, namely, energy sustainability: RES uptake is still slow in many countries – and this is particularly true for developing and emerging countries (Tabrizian, 2019). Therefore, policymakers may rebalance the energy trilemma and may give more emphasis to environmental sustainability if RES uptake and the energy transition is to be a success.

One prime example where a misfit of RES targets and actual policy reforms is apparent is Indonesia (Gunningham, 2013). For many years, policymakers in Indonesia have relied on fossil power plants, mainly coal-fired power plants, to provide their population with reliable (i.e., energy security) and affordable (i.e., energy equity) electricity. Since Indonesia has not made much progress with regard to the liberalization described above, its current energy system is still heavily dependent on state control. With the country having considerable coal, gas, and oil resources, fossil power plants are currently seen as a low-cost way to generate electricity. In 2014, the government announced ambitious plans to increase the share of RES in Indonesia's energy mix. Given these targets, what is now necessary are reforms of Indonesia's energy system to shift the country's emphasis from fossil fuels to RES. However, the past reforms that were undertaken to make renewables more cost-competitive with conventional power plants have so far proven to be less successful in Indonesia (Ditjen EBTKE, 2019). Therefore, the government is in search of clear policy directions to push RES uptake in the coming years.

[1] The terms 'restructuring' and 'liberalization' are synonymous and refer to "attempts to reorganize the roles of the market players, the regulator and/or redefine the rules of the game, but not necessarily 'deregulate' the market" (Sioshansi (2006)); accordingly, we use the two terms interchangeably in this paper.

While some small to medium scale reforms have been discussed in literature with respect to increasing the share or RES in the Indonesian energy system (see, e.g., ADB (2019) or Burke et al. (2019)), in our paper we instead suggest and address a major reform of the Indonesian electricity sector, namely, the introduction of an energy-only wholesale market for electricity that currently does not exist and, in particular, a corresponding new electricity pricing regime. The latter relates to the question of how wholesale prices are implemented, for instance in form of a nodal pricing, a zonal pricing, or a uniform pricing system (Weibelzahl, 2017). These three systems differ in the extent to which electricity trade accounts for scarce transmission capacities of the network and whether post-trade redispatch is necessary. We rely on experiences from countries which have already successfully restructured their energy systems including Europe and the US. In particular, we draw on experiences from these countries regarding the benefits and challenges of each pricing regime.

Central to our research is that any major reform that aims at improving energy sustainability in Indonesia must also meet the other two ongoing major objectives of the government (i.e., energy security and energy equity). Hence, the focus of our research is to address the following research question (RQ):

How can different pricing regimes support Indonesia in balancing its energy trilemma?

To answer our RQ, we develop an economic model that is based upon analytical modelling and allows to analyze private and public investment decisions in liberalized electricity markets, i.e., we consider both generation and transmission investments. In particular, we develop a model for each of the three standard pricing regimes that have emerged from the first wave of electricity market restructuring, i.e., nodal pricing, zonal pricing, and uniform pricing (Weibelzahl, 2017). The three model variants allow to examine and to compare the investments obtained under each of the three pricing regimes and the respective impact on the energy trilemma.

To illustrate the applicability of our model, we further evaluate it with a simplified version of the Indonesian electricity network – in particular, we focus on the Sumatra and Java-Bali electricity subnetworks. Subsequently, we discuss our results in the light of our RQ. In particular, we broaden the discussion towards an energy justice perspective on the energy trilemma proposed by Heffron et al. (2018). The concept of energy justice basically aims at enforcing the observance of human rights across the entire energy life-cycle; it has five forms at its core: distributive, procedural, recognition, restorative, and cosmopolitan justice (Heffron and McCauley, 2017). Thus, we demonstrate the importance for Indonesian policymakers to improve not only energy sustainability, but also to balance it with the interests of energy equity and energy security. Ultimately, we outline a first transformation pathway for a more sustainable and just transition to a low-carbon economy in Indonesia.

With our paper, we aim to contribute to research and practice in at least five ways. First, based on our models, we illustrate how the introduction of liberalized markets, and of market-based pricing in particular, may support countries like Indonesia in balancing the energy trilemma and in reaching goals concerning an increasing RES penetration. Second, building on the experiences from other countries that already implemented market-based pricing mechanisms, our paper illustrates how the models may work in practice resp. how they may work in Indonesia, an emerging lower middle-income economy (The World Bank, 2020c). Third, our paper analyses and discusses first and preliminary results using a simplified network model of Indonesia (i.e., the introduction of markets and different electricity pricing regimes) from an energy justice perspective. Fourth, our model may generally provide policy-relevant insights for investment institutions (e.g., for development banks or other investment funds) by supporting decisions on funding strategies concerning energy transition projects. And finally, our research demonstrates how reform in the electricity sector can result in more just outcomes for society from policy decisions that aim to develop a low-carbon economy.

This paper is organized as follows. Section 2 first presents insights and experiences obtained from existing literature on electricity pricing regimes; secondly, the status quo of the Indonesian energy system and previous reform attempts are outlined. In Section 3, we develop our pricing models. Section 4 presents the data basis for the simplified Sumatra and Java-Bali electricity networks used in our evaluation. The results of our three pricing regimes are discussed in Section 5; in particular, we discuss the results from an energy justice perspective on the energy trilemma. The penultimate section of our paper, Section 6, summarizes the implications for research and policymakers. Finally, Section 7 concludes the paper.

2 Theoretical background

This section provides relevant background for our analysis: First, we give a brief overview of electricity pricing regimes in the context of the worldwide electricity market liberalization; second, we describe the current Indonesian energy sector and respective policy reforms building the basis for our model evaluation (see Sections 4-6).

2.1 Electricity pricing regimes

Within the last decades, the worldwide era of liberalization has also affected many energy systems (Pollitt, 2012). For the case of electricity systems, restructuring typically took shape through the introduction of wholesale markets for electricity and the corresponding implementation of different electricity pricing regimes (Weibelzahl, 2017). Policymakers in Chile, England and Wales, and Norway were among the first to introduce wholesale markets for electricity (Hogan, 2002) – others in many more countries around the world were to follow their example. Introducing these new markets, policymakers aimed at improving both the operational and economic efficiency of electricity sectors to be able to provide electricity reliably (i.e., energy security) and at low costs (i.e., energy equity) to consumers (Conejo and Sioshansi, 2018). Not only by creating markets for free trade but also by breaking up vertically integrated monopolies, policymakers intended to foster competition, thereby lowering the prices and incentivizing private project developers to invest in generation capacity (Pollitt, 2012).

Various forms of restructured electricity markets have emerged around the world. They typically have in common that the transmission sector remains highly regulated, and so are also the associated public network investments (Vogelsang, 2006). However, there are differences in particular with respect to how wholesale market trade is organized using different design options for the trade between different market players including, e.g., electricity generating companies or consumers. In particular, literature mainly discusses three different electricity pricing regimes, namely nodal pricing, zonal pricing, and uniform pricing (Gan and Bourcier, 2002; Leuthold et al., 2008; Weibelzahl, 2017). These different pricing regimes vary in how they manage limited transmission capacities of the network and how pricing rules take these scarce capacities into account.

Under a nodal pricing regime, all economic and physical restrictions of the system are perfectly "integrated", i.e., the market equilibrium takes the relevant production related, consumption related, and transmission related constraints into account (Singh et al., 1998). Therefore, the resulting node-specific prices adequately reflect local and temporal scarcity in form of price peaks; for more original work on nodal pricing see, e.g., Bohn et al. (1984), Schweppe et al. (1988), Hogan (1992), and Chao and Peck (1996). In contrast, under a zonal pricing regime, nodes are pooled into different pricing zones that share a common price (Bjørndal and Jørnsten, 2001). Hence, the zonal regime only considers physical restrictions between the assumed price zones, while intra-zonal transmission restrictions are neglected. This requires ex-post redispatch of the transmission system operator (TSO) resulting from the relaxation of the relevant physical transmission rules within zones during spot market trade, as the responsible TSO may not be able to transport the produced electricity to the corresponding consumers. Therefore, redispatch takes place in a second step, restoring physical feasibility at minimal cost (Burstedde, 2012; Egerer et al., 2016). In this context, redispatch refers to either upregulation or downregulation of different electricity generators in order to ensure feasible electricity flows in the network without an overflow on the transmission lines; for more original work on zonal pricing see, e.g., Bjørndal et al. (2003) and Oggioni and Smeers (2013). Finally, under a uniform pricing regime, physical transmission constraints are completely ignored at the electricity exchange (Kahn et al., 2001). Rather, only production related and consumption related constraints are accounted for. In direct consequence redispatch takes place in a second step to deal with the corresponding transmission infeasibility.

The chosen pricing regimes will directly determine the profitability of private investments in new generation capacity. Obviously, while under a uniform pricing system no location-specific investment signals are received by investors/operators of a power plant, nodal prices reward investments at locations where generation capacity is scarce at a higher extent. Nevertheless, the high number of different prices of a nodal pricing regime is highly complex and may be perceived as being unfair, as electricity consumers located at different network locations will typically pay different prices. Ultimately, the question of choosing an adequate pricing regime is a highly complex decision for policymakers. For all of the three regimes, there are valuable experiences regarding the benefits and challenges from countries which have already successfully liberalized their electricity markets, e.g., the US (currently using nodal pricing; see, e.g., Gil and Lin (2013)), Norway (currently using zonal pricing; see, e.g., Bjørndal and Jørnsten (2001)), and Germany (currently using uniform pricing; see, e.g., Müsgens et al. (2014)). Against this background, Table 1 summarizes some of the main benefits and challenges of the three different pricing regimes experienced in the past. It also underlines that no "best" pricing regime exists, but rather that the three regimes have quite different characteristics that must best fit the current circumstances of a given country.

Table 1. Experiences with different pricing regimes. Source: Created by Authors (2020) from review of: Bjørndal and Jørnsten (2001), Gil and Lin (2013), Müsgens et al. (2014), Weibelzahl (2017).

	Benefits	Challenges
Nodal pricing	• Efficient dispatch of generation • Local signals/incentives in long-run investments • No redispatch necessary	• High system complexity • Many small submarkets with possibly low competition and market power abuse • Fluctuating local prices

Zonal pricing	• Reduced number of different prices • Increased intra-zonal competition • Price stability	• Possibly inefficient dispatch of power plants • Reduced signals for flexibility • No local signals/incentives for long-run investments • Difficult determination of zonal boundaries • Possibly high redispatch costs and associated reallocation issues • Defining adequate remuneration for redispatch services
Uniform pricing	• High market liquidity • Low system complexity • Relatively high competition • Price stability	• Possibly inefficient dispatch of power plants • Possibly inefficient long-run investments • Possibly high redispatch costs and associated reallocation issues

As already highlighted before, the transmission sector is typically highly regulated, which implies that network investment decisions are often made by some kind of a public entity. In addition to the already high complexity of a pure cost-benefit analysis (with respect to the effects on the short-run network operation) of a possible network extension project, what even more complicates network investment decisions is the fact they will generally impact electricity prices under the chosen pricing regime. In turn, price changes may influence private investments in new generation capacity as described above. Therefore, the chosen pricing regime will also have a severe impact on the question of which public network investments should be made in order not to negatively affect investment behavior of private companies. Ultimately, this clearly highlights the high interdependency of the different investment decisions and the many possible side-effects associated with an introduction of a pricing regime that can hardly be anticipated without the help of quantitative economic models such as the ones introduced in Section 3.

To give an overview of the relevant public and private decision making under each of the three pricing regimes, we illustrate the corresponding decision sequences accounting for both long-run investment decisions and short-run market clearing in Figure 1. Here, public network investment choices (decision level 1) are followed by expected private generation investments and spot market trade (decision level 2). In the case of zonal and uniform pricing, spot market trade will be followed by redispatch of the TSO (decision level 3) to restore transmission feasibility.

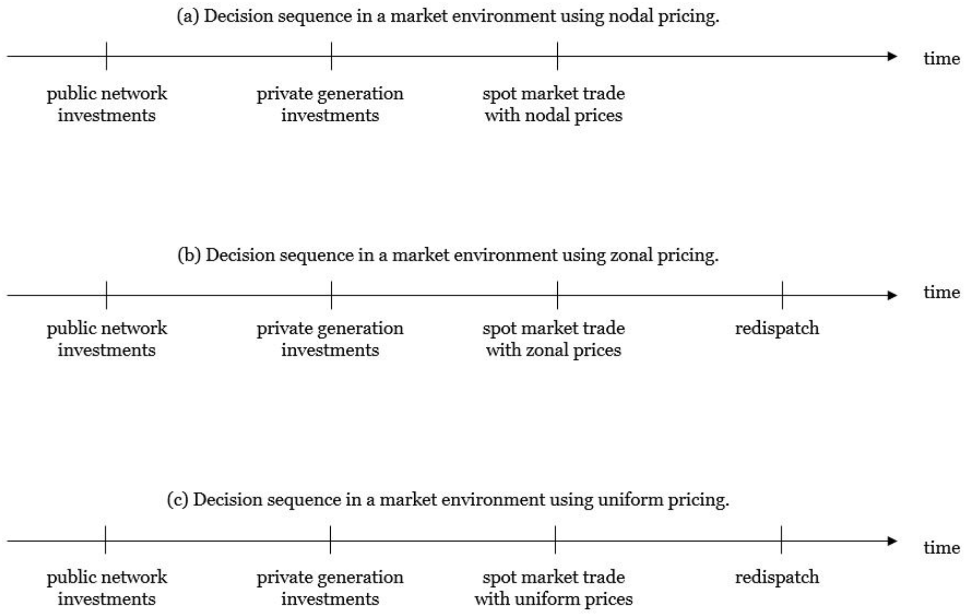

Figure 1. Decision sequences under different pricing regimes. Source: Created by Authors (2020).

2.2 The Indonesian energy system

Given the different pricing regimes, our paper analyzes how these pricing regimes may support Indonesia to increase its RES generation. Therefore, subsequently we briefly give an overview on the Indonesian energy sector.

With more than 267 million citizens, Indonesia is the world's fourth populous country (The World Bank, 2019b). It has the biggest economy in Southeast Asia, and ranks 16th among the world's economies in terms of total GDP (The World Bank, 2019a). Positioned between the Indian and Pacific oceans, Indonesia is additionally the world's biggest island state consisting of 17.508 islands, around 6.000 of which are inhabited. With respect to its electricity sector, the term 'archipelago' perfectly describes the Indonesian electricity network, which consists of eight major and around 600 isolated networks (Burke et al., 2019). During the first wave of global electricity market restructuring, Indonesia has made first privatization efforts by opening its electricity generation sector to Independent Power Producers (IPPs) in the 1990s (Maulidia et al., 2019). As of today, however, there are only a few IPPs in Indonesia and liberalization can be seen as incomplete. In particular, the state-owned enterprise *Perusahaan Listrik Negara* (PLN) and its subsidiaries still own more than 75% of generation capacity in the country (Maulidia et al., 2019). No further significant privatization has taken place, which is why – except from electricity generation – Indonesia's electricity sector is controlled by the state, i.e., PLN controls the network and sells electricity to consumers (Burke et al., 2019). In particular, the Indonesian electricity sector is currently organized as a single-buyer market (Sakya et al., 2006). Typically, under such a market design, countries preserve an artificial monopoly over the electricity sector even after the vertically integrated state owned enterprise (i.e., PLN in Indonesia) is formally unbundled (Lovei, 2000). In fact, PLN buys all produced electricity in Indonesia (as a single buyer) and resells it to electricity consumers at regulated prices.

In terms of energy security, Indonesia has struggled to provide its citizens with access to electricity and was performing poorly for many years in this respect compared to other Southeast Asian countries (Maulidia et al., 2019). In 2010, roughly 14 million Indonesians (i.e., 5.85% of the population) have had no access to electricity (The World Bank, 2020a), which is why improving the electrification rate was one key priority of policymakers in the past decade (Maulidia et al., 2019). Indeed, by 2017 the electrification rate has improved: Now only 4.9 million Indonesians (i.e., 1,86% of the population) were without electricity access (The World Bank, 2020a). However, this number is misleading. First, electrification varies from region to region in Indonesia. For example, while the electrification rate is 100% in Java, outside of Java it is only 90.45%; in regions like Papua (42.5%) or Jambi (51.91%), electrification is significantly lower (PT PLN, 2019a). Second, power cuts are frequent for many Indonesians across all regions (Gunningham, 2013). The Indonesian electricity network is still very unreliable since there is a lack of generation and network capacity.

In terms of energy equity, Indonesia is making efforts to keep retail prices low for its citizens in order to combat poverty. In 2010, roughly 38 million Indonesians (i.e., 15.7%) lived in poverty, i.e., on $1.90 a day (The World Bank, 2020b). Against this background, ensuring low retail prices for electricity was and still is a key measure for the Indonesian government in its fight against poverty (Maulidia et al., 2019). This is why in Indonesia retail prices are set by the government as described above. In order to improve both energy security and energy equity, Indonesia's policymakers have focused on the expansion of fossil power plants – above all, of coal-fired power plants. Here, the policymakers' rationale is based on the supposed advantages of coal compared to other options. Not only does Indonesia have large domestic coal reserves, but also coal-fired power plants are capable of providing the necessary base load power (Gunningham, 2013). Further, coal-fired power plants are viewed as been easily financed and built quickly. To support the domestic production and thereby ensure adequate electricity supply and lower the costs of electricity production, the government ultimately subsidizes fossil fuels like coal or oil.

This focus on an energy supply chain based on fossil fuels has resulted in a situation where the third horn of the energy trilemma, energy sustainability, is mainly neglected in Indonesia. Today, RES like solar or wind only make up a fraction of Indonesia's energy mix – despite the country having a huge renewable potential (Dutu, 2016). Only in 2014, the government has announced ambitious goals to develop RES in Indonesia: compared to 6% in 2014, RES are to account for 23% of the energy mix by 2025 and even for 31% by 2050 (Maulidia et al., 2019). However, recent estimates suggest that Indonesia will not reach its 2025 and 2050 goals at current RES development rates (Burke et al., 2019). One of the key barriers to RES development is that the current design of the Indonesian energy system does not allow RES to become competitive with fossil power plants (Burke et al., 2019; Maulidia et al., 2019). What is therefore necessary is a fundamental reform of the energy system so that Indonesia is able to achieve its RES targets – and does not end up locked into a fossil fuel future (Liebman et al., 2019).

Indeed, the Indonesian government has launched a series of reforms over the past ten years to strengthen RES. However, these reforms were not very successful in terms of market penetration of RES. For example, within the last ten years there have been repeated efforts by the Ministry of Energy and Mineral Resources (MEMR) to push the development of solar PV in Indonesia. From 2013 onwards, MEMR tried to improve the situation for developers through five key regulations (i.e., No. 17/2013, 19/2016, 12/2017, 50/2017, and 4/2020) (Kennedy, 2018). In 2013, MEMR introduced the first auction program for solar PV in Indonesia (Reg. No. 17/2013) (MEMR, 2013). Although the program covered 140 MW in over 80 locations, only two projects were realized due to protests by PLN and local manufacturers who opposed the favorable tariffs for solar PV developers. Moreover, the two actually realized projects were not implemented by private investors but rather by two state-owned companies (Kennedy, 2018).

In 2016, MEMR then introduced a feed-in tariff for solar PV projects, collectively covering at least 5.000 MW (Reg. No. 19/2016) (MEMR, 2016). However, the regulation included restrictions on project size and foreign ownership, discouraging international developers. Only a couple of months later, these feed-in tariffs were abandoned (Kennedy, 2018). Instead, from 2017 on, MEMR regulated the tariffs solar PV developers can charge to PLN (Reg. No. 12/2017) (MEMR, 2017b). Tariffs were based on and limited to 85% at maximum of local and national average cost of generation. In addition, they were geographically differentiated (Kennedy, 2018). Reacting to new protests by stakeholders, Reg. No. 12/2017 was eventually replaced by Reg. No. 50/2017 (MEMR, 2017a). One major difference between the two regulations is that RES developers were now forced to transfer ownership of their facilities to PLN upon completion of power purchase agreements. In combination with tariff limits, the situation for investments in RES-plants was not attractive in terms of recovering project costs (Kennedy, 2018). In 2020, MEMR introduced Reg. No. 4/2020 which stipulates amendments for Reg. No. 50/2017 to overcome key items in Reg. No. 50/2017 that had become barriers for RES development (e.g., at the end of the Power Purchase Agreements IPPs no longer must transfer the ownership of their facilities to PLN). The amendments provide more flexibility for investors and aim to accelerate RES growth in Indonesia.

To summarize, Indonesia's energy policy to promote RES development to date has suffered from several major changes in direction (e.g., the shift from feed-in tariffs to regulated tariffs) as well as from an overall tendency to retain at least some state control over new projects. The governments' RES development strategy has therefore not proven successful so far. Ultimately, the government is in search of clear policy directions to promote an increase of RES-plants in the coming years. In the next section we will therefore develop a model to assess the impacts of a major reform in Indonesia that builds on the introduction of an energy-only wholesale market.

3 Model development

3.1 Notation and economic quantities

In this section, we first introduce the economic setup for the three pricing models of nodal, zonal, and uniform pricing that will be presented in more detail in Section 3.2. Table 4, Table 5, and Table 6 in Appendix A provide a short summary of the main sets, parameters, and variables used in our paper.

3.1.1 Planning horizon and electricity network

$T = \{1, \ldots, |T|\}$ describes the finite planning horizon. In addition, we assume an electricity network $\mathcal{G} = (N, L)$ that consists of a set of network nodes N and a set of transmission lines L interconnecting the different nodes.

We describe each transmission line $l \in L$ using its maximal transmission capacity $\bar{f}_l$ and its susceptance B_l. Accounting for possible network investments of a public entity like a responsible TSO, the subset $L^{\text{new}} \subseteq L$ collects all candidate transmission lines for investments by the responsible TSO. In analogy, the subset $L^{\text{ex}} \subseteq L \setminus L^{\text{new}}$ collects all existing transmission lines of the network $\mathcal{G}$.

As new transmission lines are typically characterized by huge fixed costs, network investments are modelled as zero-one decisions using a binary variable $w_l \in \{0, 1\}$. The latter is equal to one if and only if $l \in L^{\text{new}}$ is built. Investments in a line l are described by the given cost parameter i_l.

3.1.2 Electricity demand

$C \subseteq N$ collects all nodes of the network where electricity consumers are located at. We assume elastic long-term demand for each time period t and demand node $c \in C$ using the following linear demand function:

$$\pi_{ct}(d_{ct}) = a_{ct} - b_c d_{ct} \qquad \forall c \in C, t \in T. \tag{1}$$

In the inverse demand function (1), d_{ct} denotes the endogenous demand quantity of consumer c in time period t, while a_{ct} and b_c are the ex-ante given parameters that specify the actual demand function. $\pi_{ct}(d_{ct})$ gives the resulting prices for a given quantity of d_{ct}. We note that the assumption of elastic demand is quite common in the electricity market literature; see, e.g., Chao and Peck (1996), Bjørndal and Jørnsten (2001), Bjørndal et al. (2003), Ehrenmann and Smeers (2005), Bjørndal and Jørnsten (2007), Pechan (2017), or Weibelzahl and Märtz (2020).

Using the above demand function, gross consumer surplus, which describes the aggregated monetary consumer benefits, is given by:

$$\sum_{t \in T} \sum_{c \in C} \int_0^{d_{ct}} \pi_{ct}(h) dh = \sum_{t \in T} \sum_{c \in C} \left(a_{ct} - \frac{b_c}{2} d_{ct} \right) d_{ct}. \tag{2}$$

3.1.3 Electricity generation

Renewable electricity generators. Let us be given a set of carbon-neutral, renewable electricity generators R. The subset $R_n \subseteq R$ comprises all renewable generators that are located at network node $n \in N$.

We assume that the set of generators R consists of both existing and candidate generators, i.e., we partition the set of renewable generators R into a set of existing generators R^{ex} and a set of candidate generators R^{new}. Corresponding investments of i_r per unit of installed generation capacity $\bar{y}_r^{\text{new}}$ arise for each candidate generator. In analogy, $\bar{x}_r^{\text{ex}}$ describes the installed capacity of an existing generator.

Accounting for fluctuations in power production, for each generator r we assume a relative availability $\alpha_{rt} \in [0, 1]$ of electricity generation capacity in a time period t. As this parameter refers to the relative availability of the corresponding resources like wind or sun, it depends both on the time period t and the location of the generator, e.g., at night there will be no sun with an availability of zero. Thus, in each time period and for each renewable generator the maximum electricity output is limited by $\alpha_{rt}\bar{x}_{rt}$. Given this capacity bound, the actually chosen electricity output is then modeled by the variable $x_{rt} \geq 0$. Variable per-unit production costs are described by $v_r \geq 0$.

Conventional electricity generators. The set G gives all conventional electricity generators in the system. Analogous to the renewable generators above, we describe by $G_n \subseteq G$ the subset of conventional electricity generators located at network node $n \in N$.

A generator $g \in G$ is described by its variable per-unit production cost $v_g \geq 0$. The endogenous variable $y_{gt} \geq 0$ gives the realized electricity output in period t of generator g. Similar to renewable generators, we partition the set of conventional generators G into a set of pre-existing generators G^{ex} and a set of candidate generators G^{new}. The latter can be invested in with investments of i_g per unit of installed generation capacity $\bar{y}_g^{\text{new}}$. For all existing generators, the corresponding generation capacity is given by $\bar{y}_g^{\text{ex}}$.

3.2 Modelling different pricing regimes

In the following we develop the models for the three different pricing regimes; see also Grimm et al. (2016) and Weibelzahl and Märtz (2020) for similar models. In particular, we will present the decision levels (hereinafter: levels) under each of the pricing regimes according to Figure 1 in Section 2.1 step-by-step. From a mathematical point of view, our models represent multilevel optimization problems, where the different players anticipate the optimal decisions taken of the other players on subsequent levels, e.g., the TSO chooses optimal line investments on the first level forming expectations on optimal private generation investments, spot market outcomes, and necessary redispatch interventions on the subsequent levels.

The formulation of the public network investments of the TSO, i.e., decision level 1, (see Section 3.2.1) is identical for all of the three regimes. As decision level 2, i.e., expected private generation investments and spot market trade, as well as decision level 3, i.e., necessary redispatch of the TSO, differ for each of the regimes, we model these levels in regime-specific sections (see Sections 3.2.2, 3.2.3, and 3.2.4).

3.2.1 Public network investments of the TSO (decision level 1)

On the first level and for all three pricing regimes, we assume a benevolent TSO that chooses a network expansion plan maximizing welfare of the whole system:

$$\max \sum_{c \in C} \sum_{t \in T} \int_0^{d_{ct}} \pi_{ct}(h) \mathrm{d}h - \sum_{r \in R} \sum_{t \in T} v_r x_{rt} - \sum_{g \in G} \sum_{t \in T} v_g y_{gt} - \sum_{g \in R^{\text{new}}} i_r \bar{x}_r - \sum_{g \in G^{\text{new}}} i_g \bar{y}_g \\ - \sum_{l \in L^{\text{new}}} i_l w_l \tag{3}$$

The TSO accounts for the integrality of its network-investment decisions and expects optimal private generation investments as well as spot market (and redispatch) outcomes of the subsequent levels (see also the following sections).

$$w_l \in \{0, 1\} \quad \forall l \in L^{\text{new}}. \tag{4}$$

3.2.2 Nodal pricing (decision level 2)

On the second level, we model investment and spot market bidding of perfectly competitive companies for a nodal pricing system; see, e.g., Boucher and Smeers (2001), Daxhelet and Smeers (2007), Grimm et al. (2016), and Weibelzahl (2017) for the assumption of perfect competition on electricity markets. As it is well known and an established standard in literature, perfect competition allows to formulate investment and market clearing as a single welfare maximization problem given the above network investments of the TSO:

$$\max \sum_{c\in C}\sum_{t\in T}\int_0^{d_{ct}} \pi_{ct}(h)\mathrm{d}h - \sum_{r\in R}\sum_{t\in T} v_r x_{rt} - \sum_{g\in G}\sum_{t\in T} v_g y_{gt} - \sum_{g\in R^{new}} i_r \bar{x}_r - \sum_{g\in G^{new}} i_g \bar{y}_g \tag{5}$$

We first require nodal flow balance according to

$$d_{nt} = \sum_{r\in R_n} x_{rt} + \sum_{g\in G_n} y_{gt} + \sum_{l\in\delta_n^{\text{in}}(L)} f_{lt} - \sum_{l\in\delta_n^{\text{out}}(L)} f_{lt} \quad \forall n \in N, t \in T, \tag{6}$$

where $\delta_n^{\text{in}}(L)$ and $\delta_n^{\text{out}}(L)$ collect all ingoing and outgoing lines of node n, respectively.

In addition, all power flows must account for their lower and upper flow bounds:

$$-\bar{f}_l \le f_{lt} \le \bar{f}_l \quad \forall l \in L^{\text{ex}}, t \in T, \tag{7}$$

$$-\bar{f}_l w_l \le f_{lt} \le \bar{f}_l w_l \quad \forall l \in L^{\text{new}}, t \in T. \tag{8}$$

According to Kirchhoff's Laws, power flows on the different transmission lines are determined by:

$$f_{lt} = B_l(\theta_{nt} - \theta_{mt}) \quad \forall l = (n,m) \in L^{\text{ex}}, t \in T, \tag{9}$$

$$-M(1-w_l) \le f_{lt} - B_l(\theta_{nt} - \theta_{mt}) \le M(1-w_l) \quad \forall l = (n,m) \in L^{\text{new}}, t \in T. \tag{10}$$

In the above constraints, θ_{nt} gives the phase angle at node n in time period t. In addition, the parameter M is a sufficiently large constant denoted as big-M.

The phase angle of reference node 1 is set to zero ensuring unique phase angle values in the electricity system:

$$\theta_{1t} = 0 \quad \forall t \in T. \tag{11}$$

Given current weather conditions together with the undertaken private generation investments, power production is limited according to:

$$0 \le x_{rt} \le \alpha_{rt}\bar{x}_r^{\text{ex}} \quad \forall r \in R^{\text{ex}}, t \in T, \tag{12}$$

$$0 \le x_{rt} \le \alpha_{rt}\bar{x}_r^{\text{new}} \quad \forall r \in R^{\text{new}}, t \in T, \tag{13}$$

$$0 \le y_{gt} \le \bar{y}_g^{\text{ex}} \quad \forall g \in G^{\text{ex}}, t \in T, \tag{14}$$

$$0 \le y_{gt} \le \bar{y}_g^{\text{new}} \quad \forall g \in G^{\text{new}}, t \in T \tag{15}$$

Finally, all investment variables $\bar{x}_r^{\text{new}}$, $\bar{y}_g^{\text{new}}$ must be nonnegative:

$$\bar{x}_r^{\text{new}} \ge 0 \quad \forall r \in R^{\text{new}}, \tag{16}$$

$$\bar{y}_g^{\text{new}} \ge 0 \quad \forall g \in G^{\text{new}}. \tag{17}$$

3.2.3 Zonal pricing (decision level 2 and 3)

Spot market trade and private investments in new generation capacities. In the case of zonal pricing, we partition the node set N into k connected, nonempty price zones $Z_1, \dots, Z_k$. The set of price-zone indices is given by $\mathcal{Z} = \{1, \dots, k\}$, where k is specified ex-ante by the responsible public entities, e.g., regulators, governments, or TSOs. In the following, we assume a transfer-capacity based market coupling, i.e., between zones only restrictions relating to the available transfer capacities are used. In consequence, zone-specific prices do not account for possible intra-zonal network congestion but companies exclusively receive price signals incentivizing them not to exceed inter-zonal transmission capacities. For the ease of notation, we let L^{inter} be the set of all inter-zone transmission lines. Again, we model optimal investment behavior and market clearing as a single welfare-maximization problem:

$$\max \sum_{c\in C}\sum_{t\in T}\int_0^{d_{ct}} \pi_{ct}(h)\mathrm{d}h - \sum_{r\in R}\sum_{t\in T} v_r x_{rt} - \sum_{g\in G}\sum_{t\in T} v_g y_{gt} - \sum_{g\in R^{\mathrm{new}}} i_r \bar{x}_r - \sum_{g\in G^{\mathrm{new}}} i_g \bar{y}_g. \tag{18}$$

In contrast to nodal flow balance, we now only require zonal flow balance:

$$\sum_{n\in Z_i} d_{nt} = \sum_{n\in Z_i}\left(\sum_{r\in R_n} x_{rt} + \sum_{g\in G_n} y_{gt} + \sum_{l\in\delta_{Z_i}^{\mathrm{in}}(L)} f_{lt} - \sum_{l\in\delta_{Z_i}^{\mathrm{out}}(L)} f_{lt}\right) \quad \forall i\in\mathcal{Z}, t\in T. \tag{19}$$

Power flows on inter-zonal transmission lines are restricted by:

$$-\bar{f}_l \le f_{lt} \le \bar{f}_l \quad \forall l\in L^{\mathrm{ex}}\cap L^{\mathrm{inter}}, t\in T, \tag{20}$$

$$-\bar{f}_l w_l \le f_{lt} \le \bar{f}_l w_l \quad \forall l\in L^{\mathrm{new}}\cap L^{\mathrm{inter}}, t\in T. \tag{21}$$

Again, given the current weather conditions and the undertaken generation investment, power production must be feasible:

$$0 \le x_{rt} \le \alpha_{rt}\bar{x}_r^{\mathrm{ex}} \quad \forall r\in R^{\mathrm{ex}}, t\in T, \tag{22}$$

$$0 \le x_{rt} \le \alpha_{rt}\bar{x}_r^{\mathrm{new}} \quad \forall r\in R^{\mathrm{new}}, t\in T, \tag{23}$$

$$0 \le y_{gt} \le \bar{y}_g^{\mathrm{ex}} \quad \forall g\in G^{\mathrm{ex}}, t\in T \tag{24}$$

$$0 \le y_{gt} \le \bar{y}_g^{\mathrm{new}} \quad \forall g\in G^{\mathrm{new}}, t\in T \tag{25}$$

Finally, and as under nodal pricing, all investment variables must be nonnegative:

$$\bar{x}_r^{\mathrm{new}} \ge 0 \quad \forall r\in R^{\mathrm{new}}, \tag{26}$$

$$\bar{y}_g^{\mathrm{new}} \ge 0 \quad \forall g\in G^{\mathrm{new}}. \tag{27}$$

Redispatch. On the redispatch level, the TSO redispatches the contracted spot market volumes restoring feasibility of power flows while minimizing arising redispatch costs. Here, final quantities after redispatch may either be smaller, equal, or larger than the pre-redispatch quantities, i.e., the contracted spot market quantities. Throughout the paper, redispatch adjustments will be indicated by Δ, e.g., $\Delta_{y_{1,2}} = 5$ indicates that the TSO asks conventional power generator 1 to increase its production by 5 units in period 2. In the following, we will use a cost-based redispatch mechanism that is, for instance, used in Germany. Under such a mechanism, redispatch is profit-neutral and only accounts for additional or saved costs associated with a redispatch intervention in order to avoid gaming problems or market-power abuse. Redispatch-cost minimization for given spot market outcomes can therefore be stated as

$$\min \sum_{t\in T}\left(\sum_{c\in C}\int_{d_{ct}+\Delta d_{ct}}^{d_{ct}} \pi_{ct}(h)\mathrm{d}h + \sum_{r\in R} v_r \Delta x_{rt} + \sum_{g\in G} v_g \Delta y_{gt}\right), \tag{28}$$

where we also assume that both producers and consumers may be redispatched.

Similar to the above nodal pricing formulation, power balance is imposed for each node on the redispatch level:

$$\begin{aligned} d_{nt} + \Delta d_{nt} &= \sum_{r\in R_n}(x_{rt} + \Delta x_{rt}) + \sum_{g\in G_n}(y_{gt} + \Delta y_{gt}) \\ &\quad + \sum_{l\in\delta_n^{\mathrm{in}}(L)}(f_{lt} + \Delta f_{lt}) - \sum_{l\in\delta_n^{\mathrm{out}}(L)}(f_{lt} + \Delta f_{lt}) \end{aligned} \quad \forall n\in N, t\in T. \tag{29}$$

After redispatch all power flows must be physically feasible:

$$-\bar{f}_l \le f_{lt} + \Delta f_{lt} \le \bar{f}_l \quad \forall l\in L^{\mathrm{ex}}, t\in T, \tag{20}$$

$$-\bar{f}_l w_l \le f_{lt} + \Delta f_{lt} \le \bar{f}_l w_l \quad \forall l\in L^{\mathrm{new}}, t\in T, \tag{31}$$

$$f_{lt} + \Delta f_{lt} = B_l(\theta_{nt} - \theta_{mt}) \quad \forall l = (n,m) \in L^{\text{ex}}, t \in T, \tag{32}$$
$$-M(1 - w_l) \leq f_{lt} + \Delta f_{lt} - B_l(\theta_{nt} - \theta_{mt}) \leq M(1 - w_l) \quad \forall l = (n,m) \in L^{\text{new}}, t \in T, \tag{33}$$
$$\theta_{1t} = 0 \quad \forall t \in T. \tag{34}$$

Finally, when choosing an optimal redispatch, the TSO must take both the private generation investments as well as the exogenous weather conditions into account:

$$0 \leq x_{rt} + \Delta x_{rt} \leq \alpha_{rt} \bar{x}_r^{\text{ex}} \quad \forall r \in R^{\text{ex}}, t \in T, \tag{35}$$
$$0 \leq x_{rt} + \Delta x_{rt} \leq \alpha_{rt} \bar{x}_r^{\text{new}} \quad \forall r \in R^{\text{new}}, t \in T, \tag{36}$$
$$0 \leq y_{gt} + \Delta y_{gt} \leq \bar{y}_g^{\text{ex}} \quad \forall g \in G^{\text{ex}}, t \in T, \tag{37}$$
$$0 \leq y_{gt} + \Delta y_{gt} \leq \bar{y}_g^{\text{new}} \quad \forall g \in G^{\text{new}}, t \in T. \tag{38}$$

3.2.4 Uniform pricing (decision levels 2 and 3)

Spot market trade and private investments in new generation capacities. Uniform pricing can be seen as a special case of the above zonal pricing model where we only have a single price zone, i.e., $k = 1$. In direct consequence, we have the same model as in Section 3.2.3 except from the fact that zonal balance is replaced by a single market clearing constraint for the whole market:

$$\sum_{n \in N} d_{nt} = \sum_{r \in R} x_{rt} + \sum_{g \in G} y_{gt} \quad \forall t \in T. \tag{39}$$

Redispatch. Similar to the case of zonal pricing, also uniform pricing will in general require redispatch to ensure transmission feasibility. Such redispatch can be modelled in the same way as in Section 3.2.3.

4 Data and evaluation setup

In this section, we apply the models developed in Section 3 to a simplified representation of the Indonesian electricity sector. In particular, we restrict our analysis to the electricity systems of Sumatra and Java-Bali. Subsequently, we briefly outline the data basis for our computations; additional information on the data used is provided in Appendix B.

Electricity network. Our network of Sumatra and Java-Bali consists of 16 nodes, where we use one node per province in the geographical units of Sumatra and Java and one node for Bali in the geographical unit of Lesser Sunda Islands; see also Table 6 in Appendix B. Our data and assumptions concerning existing transmission lines are based on IESR (2019a) and MEMR (2019). Currently, the two islands of Sumatra and Java-Bali are not connected. We allow investments in new lines between neighboring nodes, as well as between nodes 6, 7, and 9 (Sumatra) and nodes 10, 11, and 12 (Java) to enable a possible interconnection between the two islands. For cost parameters of network investments, we refer to Chang and Li (2015). Figure 2 illustrates our network topology with the considered nodes and lines.

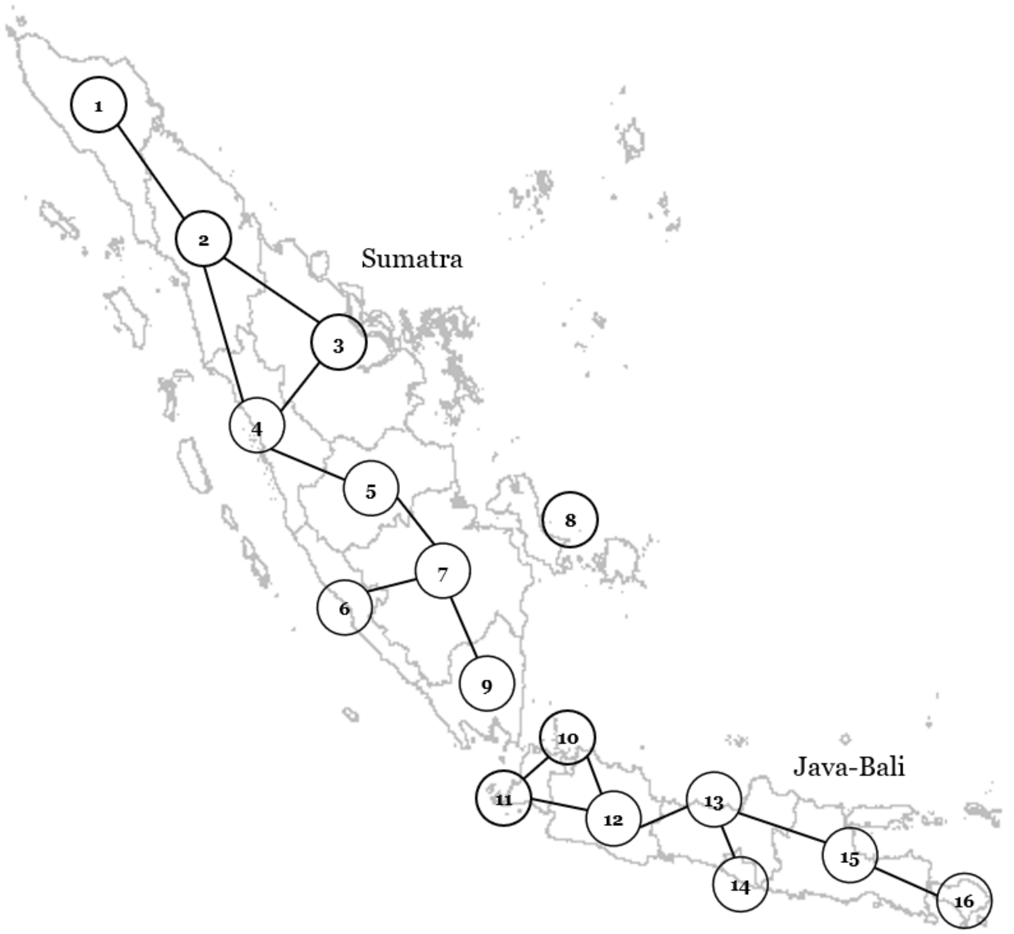

Figure 2. Network topology illustrating the considered nodes and lines.

Electricity generation. Data concerning existing generation capacities is based on PLN's 2018 *Rencana Usaha Penyediaan Tenaga Listrik* ('Power Supply Business Plan') (PT PLN, 2018); see Table 7 in Appendix B for an overview of the existing generation capacities located at each node. We consider all power plants that are currently installed as existing power plants in our model. As can be seen in Table 8, currently around 88% of the installed generation capacity is related to conventional power plants, with coal-fired power plants accounting for 53% of the total installed generation capacity. Assumptions concerning the techno-economic parameters of each generation technology are summarized in Table 8 in Appendix B. Except for coal-fired power plants, we allow investments in new generation units at all nodes. We restrict investments in new coal-fired power plants to those nodes where coal-fired power plants are currently being planned or already being built, i.e., nodes 2, 7, 9, 12, 13, and 16 (Global Energy Monitor, 2020). We do this in particular to exclude the possibility of coal-fired power plants being built in regions where this is probably not possible due to real-life restrictions such as geographical conditions or political resistance to coal-fired power plants. For investments in RES, we set limits that determine the maximum amount of cumulated capacity that can be invested in at each node. These limits are meant to reflect the respective potentials of each RES technology in each province; this data is taken from Ditjen EBTKE (2016).

Electricity demand. As real-world electricity demand functions of consumers in Indonesia cannot be observed because prices are still set by the government, we calibrate hourly demand functions for a representative day (with 24 hourly time intervals) at each node. Here, our derivation of demand functions is based on the cumulative annual demand at each node (PT PLN, 2019b), the average retail price at each node (PT PLN, 2019a), the characteristics of a typical daily load-curve of the Java-Bali electricity sector (Batih and Sorapipatana, 2016), as well as the long-term price elasticity of demand of Indonesian consumers (Burke and Kurniawati, 2018). We assume here that the demand curves we have calculated tend to be a rather conservative estimate - actual demand could therefore be higher.

5 Results

In this section, we present the computational results of our evaluation (i.e., for the Sumatra and Java-Bali electricity sectors). For a detailed analysis and discussion of the results see sections 6. We implemented the three pricing regimes using the modelling language Zimpl (see Koch (2004)) and used SCIP 6.0.2 (see Gleixner et al. (2018)) to generate corresponding mps files. The problems were then solved with the CPLEX 12.10 solver (see IBM (2019)). Given corresponding results, we then calculate various key indicators for all three pricing regimes. In particular, we compute (1) the welfare level and the consumer surplus, (2) private generation investments, (3) public network investments, (4) redispatch costs, and (5) resulting electricity prices; see Table 2 for an overview of the main computational results of the three models. For the zonal pricing regime, we partition the 16 nodes into two price zones, where nodes 1-9 belong to one price zone (hereinafter: 'Sumatra') and nodes 10-16 belong to another price zone (hereinafter: 'Java-Bali'). This partition reflects the two islands of Sumatra and Java-Bali (see Figure 2).

Table 2. Computational results for all three pricing regimes; all values except from normalized welfare and electricity prices are rounded to full values. Source: Created by Authors (2020).

		Pricing regime		
	Unit	nodal	zonal	uniform
Normalized welfare	%	100	99.20	94.06
Absolute welfare	$	65,879,555	65,352,456	61,968,708
Consumer surplus	$	83,046,180	82,525,497	81,128,565
Redispatch costs	$	-	1,050,289	5,405,162
Aggregated Renewable capacity added	MW	54,658	54,839	64,406
Aggregated Conventional capacity added	MW	17,573	18,477	7,105
Overall generation capacity added	MW	72,232	73,316	71,511
Aggregated Network capacity added	MW	4,000	3,400	12,544
Number of lines added	-	4	4	13
Aggregated Renewable investment	$	8,010,733	8,049,150	10,646,770
Aggregated Conventional investment	$	2,445,731	2,573,267	989,516
Aggregated Network investment	$	288,000	244,800	903,168
Average electricity price	$/MWh	30.94	28.83	32.45
- for consumers in price zone 'Sumatra'	$/MWh	29.10	25.83	32.45
- for consumers in price zone 'Java-Bali'	$/MWh	33.30	32.69	32.45
Aggregated renewable generation	MWh	456,087	456,347	430,912
Aggregated conventional generation	MWh	238,973	228,048	222,275
Aggregated electricity consumption	MWh	695,058	684,395	653,188

First, we calculate the welfare levels realized under the three pricing regimes (i.e., we calculate the aggregated difference between consumer surplus and all costs of production and investments). In line with literature that considers nodal pricing to be most efficient in terms of welfare (Weibelzahl, 2017), we normalize the welfare realized under the nodal pricing regime to 100%. Our results illustrate that welfare decreases when nodes are pooled into one or more zones: Under zonal and uniform pricing, the normalized welfare realized is 99.20% and 94.06%, respectively. However, when comparing the uniform to the zonal pricing regime, our results illustrate that market splitting (i.e., introducing two price zones) increases welfare. In addition to the welfare levels, we compute the (gross) consumer surpluses realized under each pricing regime (i.e., the monetary benefits for consumers). Here, the order is the same as before, with nodal pricing yielding the highest and uniform pricing yielding the lowest consumer surplus. While we note that level of welfare and consumer surplus does not differ enormously over the three pricing regimes, our results depict a clear decreasing trend of welfare and consumer surplus from nodal over zonal to uniform pricing.

Second, we compute the private investments in renewable and conventional generation. With respect to renewables, the maximum capacity of 64,406 MW is invested under the uniform pricing regime. Under the zonal and nodal pricing regimes, approximately 10,000 MW less renewables are invested each, with 54,839 MW and 54,658 MW, respectively. With respect to conventional generators, the order is exactly the other way round: 17,573 MW is invested under the nodal pricing regime, 18,477 MW is invested under the zonal pricing regime, and only 7.105 MW is invested under the uniform pricing regime.

Third, we calculate the corresponding network investments. Both, under the nodal and the zonal pricing regimes, four transmission lines are built each; under the uniform pricing regime, 13 lines are built. Moreover, our results illustrate that under all three pricing regimes the two islands of Sumatra and Java-Bali are being connected via transmission lines. The considerably higher number of lines invested under the uniform pricing regime can be explained by referring to the decision levels of the three models: Under the uniform pricing regime, private firms cannot and/or do not take into account network constraints and make their investment decisions independently from these constraints meaning they consider the network as a “copperplate” (Weibelzahl, 2017) and do not receive location-specific investment signals. Accordingly, the TSO must adapt the network to the anticipated higher generation and invests in the appropriate lines so that electricity can be transported to the respective consumers. This is also reflected in the respective redispatch costs.

Fourth, we compute the redispatch costs. Under uniform pricing, the redispatch costs are five times higher than the redispatch costs realized under zonal pricing. Following a similar logic as with the number of lines constructed, the higher redispatch costs observed under uniform pricing result again from private firms completely ignoring network constraints when making their investment decisions. In contrast, while the private firms do not consider the intra-zonal network constraints under zonal pricing, they nevertheless account for the inter-zonal network constraints. Therefore, and in line with literature (Ding and Fuller, 2005), redispatch costs are lower under the zonal pricing regime compared to the uniform pricing regime.

Fifth, we calculate resulting electricity prices for the three pricing regimes. On average (i.e., over all nodes and time periods) consumers pay the lowest electricity price under the zonal pricing regime, followed by the nodal pricing regime. The highest average electricity price is realized under the uniform pricing regime; see Section 6.2 for a more in-depth analysis and discussion of the resulting electricity prices.

6 Discussion and implications

In this section, we discuss our results and derive implications for policy and research. In particular, we examine the results from three perspectives: First, we address our RQ and discuss how the three pricing regimes may support Indonesia in balancing its energy trilemma. Second, we broaden our discussion towards an energy justice perspective on the energy trilemma. And finally, we summarize the implications that follow from the previous steps and highlight a transition path for Indonesia towards a just low-carbon energy system.

6.1 Balancing Indonesia's energy trilemma

To-date and as discussed in detail in Section 2.2, Indonesian policymakers have traditionally focused on energy security and energy equity. In 2014, by announcing its ambitious goals to develop RES, the government demonstrated its political will to put more emphasis on the previously neglected third horn of the energy trilemma, namely, energy sustainability. In line with our RQ, our primary aim in this paper is to examine how the introduction of a wholesale market for electricity, and of different electricity pricing regimes in particular, may support Indonesia in balancing its energy trilemma. Hence, we analyze and discuss the impacts of the three pricing regimes on the horns of the energy trilemma in the following.

Energy sustainability. This horn of the energy trilemma emphasizes the impacts of all energy-related activities on the environment. Assuming that RES in general have a less damaging impact on the environment than conventional power plants, e.g., through lower greenhouse gas (GHG) emissions, it would therefore be preferable to choose the pricing regime with (1) the most RES and/or (2) the fewest conventional power plants. Based on the results derived from our models and using the simplified representation of the Sumatra and Java-Bali electricity systems, this would be the uniform pricing regime. Compared to the other two pricing regimes, under the uniform pricing regime around 10,000 MW more RES capacity and less conventional capacity is added. The RES capacity added under nodal and zonal pricing is very similar. In terms of new conventional generation capacity, under nodal pricing around 900 MW less is invested than under zonal pricing.

Energy security. This horn of the energy trilemma emphasizes that adequate generation capacity is available and that the generated electricity can be reliably transported to the consumers. Our results indicate that all three pricing regimes incentivize additional investments that are remunerated via prices: As described in Section 5, both renewable and conventional generation capacity are added under each pricing regime. In addition, under all three pricing regimes the TSO invests in the necessary network capacity to integrate the private investments in a best possible way into the overall system. As private investments vary between the three pricing regimes, also optimal network investments depend on the respective market design. In particular, our results illustrate that under nodal and zonal pricing, the TSO would built only four new lines with an aggregated capacity of 4,000 MW and 3,400 MW, respectively, while under uniform pricing 13 new lines are constructed with an aggregated capacity of 12,544 MW. Ultimately, all three systems contribute to energy security in the sense that new capacities are added to the system. However, what distinguishes the zonal and uniform pricing regimes from the nodal pricing regime with respect to energy security is that redispatch is needed under the latter two regimes. Here, it is important that redispatch is appropriately implemented, as otherwise blackouts or brownouts may occur.

Energy equity. This horn of the energy trilemma emphasizes the affordability of energy services, mainly from the perspective of consumers. Two indicators from our results allow to draw conclusions as to which pricing regime seems to have advantages for this horn of the trilemma: First, comparing the resulting electricity prices under each pricing regime reveals that the lowest average electricity price is realized under the zonal pricing regime (i.e., 28.83 $/MWh), followed by the nodal (i.e., 30.94 $/MWh) and the uniform pricing regime (i.e., 32.45 $/MWh) in second and third place, respectively. For a detailed discussion, please see Section 6.2. Second, the consumer surplus – indicating the realized monetary benefits of consumers – is higher under the nodal pricing regime than under the zonal pricing regime. The uniform pricing regime is the one that yields the lowest consumer surplus.

To summarize, our results presented in Section 5 indicate that for the simplified representation of the Sumatra and Java-Bali energy system, there may be evidence that a zonal pricing regime may support Indonesia in achieving energy equity (see Section 6.2); a uniform pricing regime may support Indonesia in achieving energy sustainability under the given input parameters; all three pricing regimes may support Indonesia in achieving energy security but vary in the exact investment amounts. The overall welfare optimum is realized under nodal pricing. However, we note that the results for the model of the zonal pricing regime are very similar to the results obtained under the nodal pricing regime: in particular, welfare decreases only by 0.80 percentage points under the zonal pricing regime compared to the nodal pricing regime. As discussed in Section 2.1, a nodal pricing regime may yield a higher complexity than a zonal pricing regime. Accordingly, when deciding which pricing regime to implement, policymakers may also reflect this circumstance. Hence, for our simplified representation, zonal pricing might actually have advantages as compared to nodal pricing. Finally, the above results underline our discussion of the three pricing regimes in Section 2.1: the three horns of the energy trilemma, policymakers focus on, no "best" pricing regime exists, but rather the three pricing regimes have quite different impacts on the three horns of Indonesia's energy trilemma. When considering the three pricing regimes, policymakers may therefore reflect which horn(s) of the energy trilemma their country needs to focus on in the future. Furthermore, policymakers may also take the concept of energy justice into account, and this is discussed further in the following section.

6.2 An energy justice perspective on Indonesia's energy trilemma

In consequence of challenges discussed in the previous section, literature highlights that the problem of balancing the energy trilemma may be resolved through energy justice; see, e.g., Heffron et al. (2015) or Heffron et al. (2018). In particular, this has recently been proposed for Indonesia by Maulidia et al. (2019). In brief, energy justice is about the application of human rights across the energy life-cycle; in particular, there are five forms of justice at its core: distributive, procedural, recognition, restorative, and cosmopolitan justice (Heffron and McCauley, 2017). Given these five forms of energy justice, applying a distribution justice perspective to our results in particular promises valuable additional insights. Subsequently, we therefore focus our analysis on the distributional effects of the three pricing regimes. However, we will briefly address also the remaining four forms of energy justice below and illustrate how they may relate to our results in the context of introducing a wholesale market for electricity in Indonesia.

Distributive justice emphasizes the distribution of benefits and negatives resulting from the energy sector (Heffron and McCauley, 2017). Against this background and based on our results in Section 5, we highlight the distributional effects for consumers as a result of the electricity prices they have to pay for under each pricing regime. First, if policymakers in Indonesia were to decide to introduce a nodal price regime, they would have to consider that the resulting electricity prices for consumers at different nodes may vary significantly; see also Table 3 for an overview of the average electricity prices that consumers would have to pay for at each node under the three pricing regimes. For instance, as Table 3 illustrates, under the nodal pricing regime, consumers located at node 6 would have to pay 27.71 $/MWh on average, while consumers located at node 8 would have to pay 39.23 $/MWh. This means that consumers at node 8 have to pay a price for electricity that is 41.5% higher than the price that consumers at node 6 have to pay on average. Although such price spreads reflect the inherent logic of a nodal pricing regime and lead to overall economic efficiency, it might be difficult to explain their necessity to consumers. As a consequence, the differences in electricity prices might be perceived as being unfair and yield acceptance problems.

Second, while the discussion in Section 6.1 demonstrates that a zonal pricing regime yields the lowest average electricity price, and this may be favorable in terms of energy equity, distributive justice focusses the perspective towards the different prices for consumers in 'Sumatra' and 'Java-Bali'. In fact, consumers in 'Sumatra' on average only pay 25.83 $/MWh, while consumers in 'Java-Bali' pay 32.69 $/MWh. This means that consumers in 'Java-Bali' pay 26.5% more than consumers in 'Sumatra'. For consumers in 'Java-Bali', therefore, a uniform pricing regime would actually be more attractive than the zonal pricing regime, as they would pay a lower price.

Third, with the uniform pricing regime, the first argument with respect to nodal pricing could be reversed. All consumers pay the same price (i.e., 32.54 $/MWh in our case) and therefore, at least from the consumer's point of view, there is no reason to feel that they are being treated unequal. However, the overall economic efficiency of the energy system significantly suffers from the fact that prices do incentivize inefficient investments on the generation side.

Table 3. Average electricity prices ($/MWh) for consumers, depending on the pricing regime. Source: Created by Authors (2020).

Node	Nodal	Zonal	Uniform
'Sumatra'			
1	28.03	25.83	32.54
2	28.03	25.83	32.54
3	28.03	25.83	32.54
4	28.03	25.83	32.54
5	28.36	25.83	32.54
6	27.71	25.83	32.54
7	28.68	25.83	32.54
8	39.23	25.83	32.54
9	25.80	25.83	32.54
'Java-Bali'			
10	35.08	32.69	32.45
11	34.56	32.69	32.54
12	32.71	32.69	32.54
13	32.69	32.69	32.54
14	32.69	32.69	32.54
15	32.69	32.69	32.54
16	32.69	32.69	32.54

Furthermore, we reflect that the overall results for nodal and zonal pricing (see Table 2) do not differ significantly. Hence, when reflecting only the zonal and uniform pricing regimes, the electricity prices in Table 3 illustrate that the difference between the zonal and uniform electricity prices for 'Java-Bali' is rather small. Consequently, regarding distributive justice, policymakers may consider whether to implement zonal pricing – from which consumers in 'Sumatra' benefit significantly – or whether to implement the uniform pricing regime – which would entail higher RES investments for the whole system.

To conclude, the previous examples illustrate that introducing a new electricity pricing regime may have significant distributional implications. Clearly, some consumers benefit from a certain pricing regime (i.e., the pay relatively low prices for electricity) while others may suffer (i.e., they pay relatively high prices for electricity). Past experience in various countries illustrates that reforms of pricing mechanisms (e.g., introducing a nodal, zonal, or uniform pricing regime) can have various adverse effects including inflicting hardship on the poor and vulnerable (Rentschler and Bazilian, 2017). In Indonesia, past subsidy reform attempts and the resulting increases in fuel prices have triggered widespread protests and rioting (Gunningham, 2013). It is therefore necessary that policymakers carefully consider the distributional impacts of introducing one of the three pricing regimes. In particular, the implementation process may be accompanied by additional measures such as, e.g., compensating vulnerable households (Rentschler and Bazilian, 2017).

As noted above, the concept of energy justice comprises four more forms of justice that may guide Indonesian policymakers by considering a major reform such as a liberalization of the electricity sector. While further information can be found in Heffron and McCauley (2017), in the following we will briefly address the four justice forms in light of our case study. First, procedural justice emphasizes the compliance with the law while preparing and implementing reforms. It includes that the needs and concerns of all stakeholders (e.g., citizens, firms, or PLN in Indonesia) are heard equally (Heffron and McCauley, 2017). For example, it is important to prevent an interest group from being able to influence political decisions to its own advantage which was a major challenge for Indonesia in the past. In 2017, lobbying by the domestic coal industry made the Indonesian government reverse its plans to put a cap on coal production (Clark et al., 2020). In line with procedural justice, such unilateral influence should be prevented.

Second, recognition justice emphasizes that rights are recognized for different groups in Indonesia (Heffron and McCauley, 2017). In particular, all individuals must be fairly represented and offered complete and equal political rights (Heffron et al., 2015). For instance, this may entail that Indonesian policymakers consider the poor and vulnerable households in particular when choosing a certain pricing regime.

Third, restorative justice emphasizes that any injustices caused by the energy sector should be rectified (Heffron and McCauley, 2017). Such a major reform of the energy system as we examine in this paper offers policymakers in Indonesia the opportunity to correct historically grown injustices in the energy system. And finally, cosmopolitan justice emphasizes that the people of Indonesia consider themselves as citizens of the world and consider the effects of their energy policy beyond Indonesia and from a global context (Heffron and McCauley, 2017). This means that the reforms of the Indonesian energy system are important not only for Indonesia itself, but also for the rest of the world and vice versa: Climate change is a global problem and if Indonesia does not succeed in reducing the emission of GHGs from its electricity production, other countries will also be affected by the environmental damage.

To conclude, complementing the discussion of our results by an energy justice perspective on introducing a new electricity pricing regime broadens the perspective towards the socially just aspects of an electricity market reform.

6.3 Policy implications and transition pathway

In this section, we summarize general policy implications that result from the discussion in the previous sections. Additionally, we outline a first transition pathway indicating when and how policymakers in Indonesia may implement the reforms necessary for introducing one of the three pricing regimes discussed in this paper.

Current research highlights that electricity markets remain a work-in-progress in South East Asia (Eberhard and Godinho, 2017). As discussed in Section 2.2, policymakers in Indonesia face challenges of providing electricity reliably and affordably to all citizens, while also increasing the share of RES in the energy mix. What is needed to cope with these challenges is a clear policy direction (Taghizadeh-Hesary and Yoshino, 2019). In our paper, we have suggested and investigated a major reform of the Indonesian energy system, i.e., the introduction of a wholesale market for electricity with one of three corresponding electricity pricing regimes. From the results discussed in Sections 5, 6.1., and 6.2, we derive the following implication for Indonesian policymakers:

There is no electricity pricing regime that addresses all three horns of the energy trilemma equally. Rather, each pricing regime may support Indonesia in achieving a specific horn. Therefore, policymakers must first decide which horn(s) they want to focus on and, based on this decision, then choose the appropriate pricing regime. For example, given that Indonesia is far behind in terms of reaching its RES targets for 2025 and beyond, the uniform pricing regime may be an appropriate option for Indonesia. If, however, the focus of policymakers remains on the affordability of electricity, the zonal pricing regime might be preferable.

Building on the previous sections and the above implications, in the following we briefly outline a transition pathway through which Indonesia may introduce one of the three pricing regimes and thereby ultimately move towards a more just energy transition. We build on Rotmans et al. (2001) who consider four phases of transition: (1) pre-development phase, (2) take-off phase, (3) acceleration phase, and (4) stabilization phase. In the pre-development phase, a country is in a dynamic equilibrium where the status quo does not visibly change. As discussed in detail in Section 2.2, Indonesia is indeed in such pre-development phase with respect to liberalizing its energy system. To move on to the take-off phase (i.e., the process of change gets underway because the state of the system begins to shift), government and energy policymakers need to start the reform process. In our context, this means that policymakers take first steps to introduce a wholesale market for electricity and implement one of the three pricing regimes discussed throughout the paper. Based on our discussion in the previous sections, policymakers should first decide what their actual goal is with respect to achieving the three horns of the energy trilemma. Next, they may choose the corresponding and appropriate electricity pricing regime and implement it. Exemplary steps that will be necessary during implementation comprise reducing the level of state control in the energy system, opening the market for independent and private parties, and establishing a power exchange with corresponding permissions. During this take-off phase, in particular, it is important that procedural and recognition justice are present. In the acceleration phase (i.e., visible structural changes take place through an accumulation of socio-cultural, economic, ecological, and institutional changes that reflect to each other), it will be important that policymakers are oriented towards set goals, e.g., in the form of milestones with exact due dates. An exemplary milestone may relate to the question of when a power exchange starts its operation. Finally, the stabilization phase reflects a phase in which Indonesia has successfully liberalized its energy system and the energy trilemma is adequately addressed through the newly introduced market mechanisms. Along all of these four phases, it is particularly important that those who are responsible for the reform as well as the future market participants acquire know-how on how a liberalized wholesale market for electricity functions, and how it should be organized efficiently. Against this background, it will be essential to actively build on the experience countries around the world have made with introducing the different pricing regimes (see, Section 2.1).

7 Conclusion

In this paper, we analyze an electricity market reform concerning the introduction of a wholesale market for electricity with respect to balancing the energy trilemma. We develop three generic models that allow policymakers to analyze the impact of introducing a nodal, a zonal, or a uniform pricing regime on the three horns of the energy trilemma in their country. We evaluate our approach using a simplified network representation of the Indonesian electricity system with first real-world data; in particular, we focus on the electricity systems of Sumatra and Java-Bali. The results of our evaluation illustrate that none of the pricing regimes is able to equally balance all three horns of the trilemma in Indonesia. However, we find that each of the pricing regimes is able to foster specific horns of the energy trilemma. Among others, we find that a nodal pricing regime maximizes welfare in Indonesia, whereas an uniform pricing regime supports energy sustainability best (i.e., an increase in RES). Furthermore, our paper entails relevant implications for both, research and practice. Our results indicate the need for a connection of the two islands of Sumatra and Java-Bali as our evaluation illustrates that under each of the three pricing regimes corresponding transmission lines may be built. According to our results, policymakers may first consider which horn of the energy trilemma they want to focus on, and then implement the appropriate electricity pricing regime in the next step. Moreover, we broaden the discussion of our results towards an energy justice perspective on Indonesia's energy trilemma. In particular, we discuss that the choice of a certain electricity pricing regime always has to be considered under its distributional effects. For example, we discuss that policymakers may consider whether to foster RES investments within the whole system (i.e. the introduction of uniform pricing) or whether to introduce zonal pricing under which consumers in Sumatra benefit while Java-Bali consumers are not significantly inferior. Based on these implications, we ultimately illustrate a transformation pathway that may guide (Indonesian) policymakers in introducing a wholesale market for electricity including one of the three pricing regimes discussed in the paper.

Although our approach is in line with current literature, there are inherent limitations we want to briefly outline here. First, the results of our evaluation are limited to the electricity networks of Sumatra and Java-Bali, while the general applicability of our developed models holds for any other country or region. Second, due to a lack of real-world data, the data of our evaluation entails several assumptions, e.g., regarding exact network capacities. Third, our models are limited regarding further policy instruments like network fees, which are not considered. Furthermore, we note that developing Indonesia's current single buyer model to a wholesale market model may be associated with practical challenges that we did not consider in our paper, e.g., Indonesia's political economy.

Future research may focus, e.g., on the integration of storages into our model that may be of relevance with respect to energy security. Moreover, research may extend our model by considering the concept of demand side flexibility and its possible effects on electricity price peaks. Of course, future research may also enhance our used data set and extend the evaluation towards all regions of Indonesia. In summary, the models developed in this paper provide a manifold foundation for research and practice regarding the analysis of impacts concerning the introduction of a wholesale market for electricity in Indonesia. In particular, our evaluation results and respective discussions may serve as a valuable basis for policymakers regarding the successful implementation of electricity market reforms.

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Appendix A. Sets, parameters, and variables

This appendix presents a summary of the main sets, parameters, and variable used in our models.

Table 4. Sets. Source: Created by Authors (2020).

Symbol	Description
$\mathcal{G}$	Electricity network
N	Set of network nodes
$C \subseteq N$	Set of consumer nodes
L	Set of transmission lines
$L^{\text{ex}} \subseteq L$	Set of existing transmission lines
$L^{\text{new}} \subseteq L$	Set of candidate transmission lines
T	Set of time periods
Z	Set of given price zones
G	Set of conventional generators
$G_n \subseteq G$	Set of conventional generators located at node n
$G^{\text{ex}} \subseteq G$	Set of existing conventional generators
$G^{\text{new}} \subseteq G$	Set of new conventional generators
R	Set of renewable generators
$R_n \subseteq R$	Set of renewable generators located at node n
$R^{\text{ex}} \subseteq R$	Set of existing renewable generators
$R^{\text{new}} \subseteq R$	Set of new renewable generators

Table 5. Parameters. Source: Created by Authors (2020).

Symbol	Description	Unit
a_{ct}	Intercept of demand function c in period t	\$/MWh
b_c	Slope of demand function c	\$/MWh^2
v_g	Variable production cost of generator g	\$/MWh
v_r	Variable production cost of generator r	\$/MWh
$\bar{x}_r$	Maximum power output of generator r	MW
$\bar{y}_g$	Maximum power output of generator g	MW
$\bar{f}_l$	Transmission capacity of line l	MWh
B_l	Susceptance of line l	MWh
i_l	Line investment cost for $l \in L^{new}$	\$
k	Number of price zones	1
i_g	Generation investment cost for g	\$/MWh
i_r	Generation investment cost for r	\$/MWh

Table 6. Variables and derived quantities. Source: Created by Authors (2020).

Symbol	Description	Unit
d_{ct}	Electricity demand at node c in period t	MWh
x_{rt}	Electricity generation of generator r in period t	MWh
y_{gt}	Electricity generation of generator g in period t	MWh
$\bar{x}_r$	Invested generation capacity of generator r	MW
$\bar{y}_g$	Invested generation capacity of generator g	MW
f_{lt}	Power flow on line l in period t	MWh
Θ_{nt}	Phase angle value at node n in period t	rad
w_l	Line extension variable for candidate line $l \in L^{new}$	{0, 1}

Appendix B. Data description

In this appendix we present more detailed information on the model inputs used.

Table 7. Overview of nodes (provinces of Sumatra and Java-Bali) of the considered network. Source: Created by Authors (2020).

Name	id
Sumatra	
Aceh	1
North Sumatra	2
Riau (incl. Riau Islands)	3
West Sumatra	4
Jambi	5
Bengkulu	6
South Sumatra	7
Bangka Belitung	8
Lampung	9
Java	
Jakarta	10
Banten	11
West Java	12
Central Java	13
Yogyakarta	14
East Java	15
Lesser Sunda Islands	
Bali	16

Table 8. Overview of existing generation capacities (MW). Source: Created by Authors based on PT PLN (2018).

id	Coal	Gas	Diesel	Hydro	Geothermal	Wind	Solar PV	Biomass	Total
1	220	380	96.2	-	-	-	-	-	696.2
2	800	1,286.4	270.6	520.9	350	-	-	-	3,227.9
3	249	432.2	420.58	114	-	-	-	0.9	1,216.68
4	406.5	-	63.09	286.5	-	-	-	-	756.09
5	12	359.2	10.4	-	-	-	-	-	381.6
6	-	-	41.7	236.3	-	-	-	-	278
7	1,277	863.9	25	23.7	-	-	-	-	2,189.6
8	93	75	126.5	-	-	-	-	11	305.5
9	454	160	0.4	174.3	210				998.7
10	-	3,539	-	-	-	-	-	-	3,539
11	6,201.3	740	-	-	-	-	-	-	6,941.3
12	2,700	2,452	-	1,985.5	1,198.7	-	-	-	8,336.2
13	5,390	-	1,396.4	305.7	60	-	-	-	7,152.1
14	-	-	-	-	-	-	-	-	-
15	6,070	3,004.6	124.88	274.9	-	-	-	-	9,474.38
16	426	-	-	-	-	0.75	0.03	-	426.78
Total	24,298.8	13,292.3	2,575.75	3,685.3	1,818.7	0.75	0.03	11.9	

Table 9. Techno-economic parameters of generation technologies. Source: Created by Authors based on IESR (2019b).

Technology	Lifetime (years)	Efficiency (%)	Investment cost ($/kW)	Variable cost ($/MWh)[a]
Coal, existing	30	34	-	26.8
Coal, new	30	42	1,525	22.1
Gas, existing	25	34	-	69.7
Gas, new	25	56	825	45.3
Diesel	25	46	800	325.5
Large hydro	25	-	1,953[b]	0.55
Small hydro	25	-	3,100	0.55
Geothermal	30	-	4,550	0.25
Wind	25	-	1,750	-
Solar PV	25	-	950	-
Biomass	25	-	1,750	3

[a] Variable cost include variable operation cost and fuel cost.

[b] In line with similar assumptions (e.g., in Handayani et al. (2017)), investment costs for large hydro are estimated at 63% of small hydro.