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Reliability-cost trade-offs for electricity industry planning with high variable renewable energy penetrations in emerging economies: A case study of Indonesia's Java-Bali grid

Yusak Tanoto [a, c, *], Navid Haghdadi [b], Anna Bruce [b], Iain MacGill [a]

[a] School of Electrical Engineering and Telecommunications and Collaboration on Energy and Environmental Markets, University of New South Wales, High Street, Kensington, NSW, 2033, Sydney, Australia
[b] School of Photovoltaic and Renewable Energy Engineering and Collaboration on Energy and Environmental Markets, University of New South Wales, High Street, Kensington, NSW, 2033, Sydney, Australia
[c] Electrical Engineering Department, Petra Christian University, Surabaya, Indonesia

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A B S T R A C T

Electricity industries in emerging economies face particular challenges in delivering affordable, environmentally sustainable, and secure power given growing demand and limited financial resources. While supply reliability is often poor and emission reductions given lower priority, solar and wind are now amongst our cheapest supply options but highly variable. Our study seeks to demonstrate the potential value of trading-off reliability standards against higher renewables and lower industry costs in future generation planning. We use an open-source, evolutionary programming-based, capacity expansion planning tool, NEMO, to solve least cost generation mixes for Indonesia's Java-Bali grid in 2030. We explicitly test the cost and emission impacts of reliability targets of 0.005%–5% unserved energy (USE), modelled as both a hard optimization constraint and a penalty price on USE in the cost function. Our results highlight that lower reliability targets can increase solar and wind penetrations, reducing CO_2 emissions while reducing industry costs. Both methods of incorporating reliability delivered similar outcomes but pricing USE had some advantages for optimization over hard constraint setting. While the impacts of lower reliability on consumers requires careful consideration, our study highlights the potential cost and emission implications of arguably unrealistic reliability targets in generation planning for emerging economies.

1. Introduction

Electricity industries in many emerging economies[1] achieve only relatively low security and reliability of supply for reasons including rapid demand growth, yet financial constraints, that result in insufficient generation and network capacity. Many of these countries also currently have a high reliance on fossil fuel generation and, certainly across much of Southeast Asia, especially coal [1]. The technical maturity, dispatchability and highly competitive costs of fossil fuel options has been a key factor in their dominant role. Their adverse environmental impacts have, understandably, been a second order concern.

Over the past decade, extraordinary technical progress, and cost reductions for several renewable energy (RE) technologies, notably wind and solar photovoltaics (PV), has seen them playing a growing role in many electricity industries, mostly in more developed jurisdictions, and supported by a range of renewable policy support mechanisms. Now, however, they are increasingly seen as cost-competitive in their own right [2]. Although countries like China and India are aiming to reduce fossil fuel in electricity generation, many emerging economies, including some in Southeast Asia,

* Corresponding author. School of Electrical Engineering and Telecommunications and Collaboration on Energy and Environmental Markets, University of New South Wales, High Street, Kensington, NSW, 2033, Sydney, Australia.
E-mail address: y.tanoto@student.unsw.edu.au (Y. Tanoto).

[1] We use the term emerging economies rather than developing countries to better acknowledge many countries' general socio-economic development progress, including income and energy access, and transition efforts towards more sustainable electricity industries. Certainly, Indonesia is likely better characterized as an emerging economy rather than a developing one. However, it still experiences far lower grid reliability than industrialized countries typically do, a characteristic shared by many other emerging as well as developing economies.

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continue to prioritize coal fired power plants in their long-term planning processes, and as policymakers have failed to limit new coal plant capacity and reduce existing units [3].

Our study aims to address the question of how electricity planning for these jurisdictions might better capture the potential generation cost reductions as well as improved environmental outcomes offered by variable renewable energy (VRE), while managing their challenges for system security and reliability. Electricity industry planners have always faced a trade-off between their objectives of reducing total industry generation costs yet also delivering secure and reliable supply versus reliability outcomes. Wind and solar offer low cost but highly variable and somewhat unpredictable generation, adding to the complexity of this trade-off. More generally there is the question of what the right level of reliability to seek to deliver. Our study particularly focuses on the question of how emerging economies can be more thoughtful about how they set reliability targets when undertaking future electricity generation planning scenarios with high renewables, and what the implications of lower reliability targets are for costs and environmental outcomes.

A large and growing number of studies has explored long-term electricity generation planning with high VRE scenarios albeit mostly for the electricity industries of industrialized economies. In emerging economies, however, these studies generally seek to obtain the 'least cost' future generation technology mix, within security and reliability 'constraints' and perhaps environmental 'constraints' or policy mechanisms. Various optimization methods and tools have been used for the cases of emerging economies electricity industries. Mondal et al. [4] assessed the potential contribution of VRE to diversify the Philippines generation mix in meeting 2040 demands using a linear programming bottom-up model, The Integrated Market Allocation-Energy flow optimization model System (TIMES). The authors compared a business-as-usual reference 'case' against alternative policy scenarios, including the imposition of a carbon tax, RE target, limited coal share, and RE subsidy. Das et al. [5] also used the tool to explore possible future power supply scenarios for Bangladesh in 2045. These comprised high power imports, higher use of VRE, and a combination of both, aimed at reducing supply cost and fossil fuel imports while maintaining energy security.

Pupo-Roncallo et al. [6] used a deterministic model-based analytical programming tool, EnergyPLAN, to analyse the impact of integrated VRE on emissions and fuel consumption reductions across a range of Colombian 2030 electricity industry scenarios. Bamisile et al. [7] also used the same tool to model a year of supply-demand balance for Nigeria's electricity sector at hourly time-steps for a large number of sustainable energy scenarios, including different combinations of VRE technologies, pumped hydro-storage and gas. Dranka and Ferreira [8] used this tool for the case of a 2050 Brazilian electricity system using 100% renewables generation. Kumar and Madlener [9] applied an integrated modelling tool, Long range Energy Alternatives Planning (LEAP), to develop a model to examine the impacts of RE in the Indian long-term electricity supply mix and estimate the CO_2 emissions. The authors considered different level of RE capacity-based scenarios. Kachoee et al. [10] also used LEAP to simulate the supply side in baseline, slow-carbon, and RE based scenarios for Iran's future electricity demand in 2045. Mirjat et al. [11] applied LEAP to assess 2050 Pakistan's long-term electricity supply side scenarios by considering the reference case, RE based, maximum clean coal, and energy efficiency and conservation scenarios.

Rady et al. [12] assessed the economic and environmental implications of possible Egypt's 2040 generation mix using a bottom-up, linear optimization model, the Open Source energy MOdelling SYStem (OSeMOSYS). The authors also tested the robustness of the scenarios through a sensitivity analysis. Dhakouani et al. [13] used the same tool to assess the potential benefits of increasing RE penetrations in the Tunisian electricity industry by 2030 through reference and targeted RE generation scenarios. Rego et al. [14] proposed a linear programming based-multiperiod optimization model to assess the impacts of different scenarios on the Brazilian electricity industry by 2033. The study focused on the demand growth and CO_2 target emissions and considering supply-demand seasonality and the peak period of demand. Afful-Dadzie et al. [15] developed a stochastic mixed integer linear programming-based model to solve electricity generation planning with and without RE targets for Ghana in 2030. The study analysed and compared scenarios findings around capacity additions, electricity demand met with RE, level of unmet demand, and electricity supply costs. Afful-Dadzie et al. [16] then applied the same method, in which focused on the setting and evaluation of 10% RE generation target policies and discussed their impacts on unmet demand and supply cost in Ghana by 2030.

These studies have certainly provided useful insights for policy makers regarding possible future electricity sector generation under different technology and cost assumptions and policy interventions. Less explored, however, has been the implications of different reliability targets of different options and, in particular, the potential trade-offs between reliability and costs.

Reliability in planning exercises is often 'set' through a constraint on unserved energy (USE). This may be set at zero reflecting that supply must always meet demand over the planning horizon. More sophisticated modelling often permits some fixed level of USE, perhaps matched to the target reliability for that jurisdiction. These targets reflect the reality that absolute 100.000% reliability can involve significantly higher industry costs given the additional generation and network capacity required to cover unexpected plant and network failures. Still, for developed countries these reliability targets are often very tight - for example, the Australian reliability standard is currently set at 0.002% USE [17]. Such targets reflect very high expectations on supply reliability and Value of Lost Load (VOLL) estimations, the USE price ($/MWh) at which the cost of providing greater reliability starts to exceed the value of this reliability to consumers.

There is of course work exploring reliability-cost trade-offs in the electricity generation planning and operation context. Ghorbani et al. [18] optimized hybrid system scenarios using two algorithms: Genetic Algorithm-Particle Swarm Optimization (GA-PSO) and Multi-Objective Particle Swarm Optimization (MOPSO). While the authors aimed to obtain a hybrid system with the lowest cost and the highest reliability by conducting reliability/cost assessment and considering several operation reliability indices, the study was carried out in the off-grid context. Saboori et al. [19] applied a mixed-integer nonlinear programming with PSO algorithm in conducting an energy storage system (ESS) planning exercise to improve network reliability. While the study assessed reliability-cost trade-offs, in terms of energy not served (ENS) compared against the cost of ESS and total operation cost, including a sensitivity analysis, the study was focused on the radial electrical distribution network. Baghaee et al. [20] utilized a MOPSO algorithm to solve reliability/cost based optimal design of a hybrid wind/PV with hydrogen storage system. While the study considered few operation reliability indices and one year period of hourly time steps operation, the analysis was done using a synthetical load data and for a micro grid.

Al-Shaalan [21,22] has discussed how reliability can be enhanced without compromising the affordability of the electricity system. While these studies have highlighted the important relationship between cost and reliability, they have been focused only on small grids without considering VRE penetrations nor other externalities such as emissions. These two aspects may significantly affect effective planning due to the trade-offs between security and economics. Röpke [23] applied a cost-benefit approach to analyse the trade-offs between RE development and supply security (reliability) targets on the German electricity market between 2010 and 2020. While the reliability levels are compared with its costs, the study focused on reliability problems of the distribution grid due to the increase of decentralised RE production. Wu et al. [24] applied Monte Carlo method to develop a stochastic long-term optimization-based model for calculating the cost of power system reliability. While the study considered trade-off between minimizing operating costs and satisfying reliability requirements, the analysis has been undertaken as a stochastic security-constraint unit commitment problem.

Our study adds new perspectives to existing studies by addressing two complexities for electricity generation planning studies that have not been fully explored to date. The first is that it explicitly explores the trade-off between future power system reliability and total generation costs, for electricity industries in emerging economies. While the very tight reliability targets generally used for modelling exercises are likely appropriate for developed electricity sectors with very high delivered reliability, many emerging economies achieve much lower reliability in practice. It is not uncommon for electricity users to suffer regular supply interruptions on near monthly, weekly, or even a daily basis. A 0.002% USE for future generation mixes misses the reality of these industry sectors. The second complexity is the implications of growing VRE penetrations on reliability. We model variable wind and solar PV generation with high temporal (hourly) and locational (choosing traces from a range of solar and wind locations) fidelity using an open-source evolutionary programming-based tool. While wind and solar now offer amongst the lowest levelized costs of electricity in many jurisdictions, their highly variable and somewhat unpredictable output raises additional reliability challenges to that posed by unexpected peak demand growth and conventional generator and network failures. Our study brings together two broad questions; appropriate system operational reliability standards, and the complexities of high VRE penetrations modelled at high temporal resolution on reliability, in the context of emerging economies' electricity industry planning.

In terms of methods, we compare the outcomes and computational effort of achieving different reliability outcomes through setting reliability as a constraint versus applying different prices on any USE. Finally, we consider how policy might drive higher VRE penetrations using carbon pricing, but with a particular focus on how industry costs should be assessed when such 'shadow' externality pricing and hence 'revenue' flows are utilized.

We demonstrate our approach for the case of Indonesia's future Java-Bali electricity grid. We use real data of hourly system demand of Java-Bali electricity grid, scaled to account for future demand growth, and conduct simulations to obtain optimum possible future generation portfolios with high VRE penetrations under a range reliability standards and carbon prices and examine their impact on the associated generation costs and emissions. While we emphasize Indonesia and use the country as a case study, electricity supply reliability poses challenges for many other emerging economies, including those with relatively high rates of access, given the challenges of demand growth and raising the capital required for investment to meet this [25,26]. Therefore, while we use the Indonesian electricity industry as our case study, the method used, and insights obtained from the analyses presented in this paper are highly relevant to other jurisdictions with similar contexts.

It is important to note here that the reliability of electricity provision has enormous significance for energy users - residential, commercial, and industrial - and that the private and broader societal costs of relatively poor reliability in many emerging economies are poorly understood but likely large. Also, the reasons for supply interruptions may have many causes other than insufficient generation capacity, often relating to grid overloading or failure. Such realities mean that many industry, commercial and even residential participants have sought self-supply options to cover grid outages, and major cost additions to improve reliability may prove challenging for many consumers. In particular, we are not arguing that electricity consumers in these jurisdictions wouldn't value greater reliability, but rather acknowledging the realities of achieved reliability at present and seeking to better understand potential cost-reliability trade-offs. Work to better understand the impacts of different levels of reliability on the demand-side is beyond the scope of our study, but clearly needed.

The rest of this paper is organized as follows. In Section 2, we briefly discuss the emerging economies' contexts for electricity industry planning, focussing on Indonesia's power sector as the selected case study, and other important aspects. Section 3 describes the method applied in this study, simulation overview, scenarios and assumptions, and the data inputs for our scenario modelling. Results and discussions are presented in Section 4, and finally, Section 5 concludes the paper.

2. Emerging economies' context for electricity industry planning: a case study of Indonesia

Electricity industries in many emerging economies are characterized by having significant demand growth hence investment challenges, and a present reliance on fossil-fuel generation despite excellent renewable resources, including VRE. This section presents an overview of the current Indonesian power sector situation, especially for the main Java-Bali grid, given its high relevance to many other electricity industries in other emerging economies in terms of underlying resources, present fossil fuel reliance, investment challenges and policy gaps for transitioning towards a more sustainable future.

2.1. Power sector profile and long-term generation planning

Perusahaan Listrik Negara (PLN), a state-owned vertically integrated utility, is responsible for managing the entire electricity industry value chain including generation, transmission and distribution, and retail in Indonesia. Total national electricity installed capacity and electricity production in 2018 was 57.8 GW and 257.5 TWh, respectively, of which 27.9% of the total installed capacity and 30.4% of the production came from Independent Power Producers (IPPs) [27]. While IPPs' contribution continues to increase in supporting government target on 100% electrification, many areas in Indonesia still experience poor electricity supply reliability. Some of the reasons include supply shortages and a combination of several factors such as operation and maintenance challenges, lack of network capacity, ageing assets, and theft [28].

The Java-Bali grid is the largest interconnected electricity network in Indonesia, serving around 60% of the total country's population. In 2018, electricity consumption and peak load in this region were reported as 165.8 TWh, or 71.4% of the total national electricity consumption, and 27 GW, respectively [27]. Generation capacity was 37.7 GW, including 7.7 GW capacity contributed by IPPs [27]. Coal dominates Java-Bali's PLN generation mix representing 54.5% of total capacity, followed by gas (35%), hydro (8.1%), geothermal (1.26%), and diesel (1.07%) [27]. Despite having the highest electrification rate among Indonesian regions, around 600,000 households in Java-Bali were reported without access to electricity in 2018 [28].

Indonesian electricity industry expansion planning, including electricity infrastructure and investment requirements, is technically undertaken by PLN. The planning has been made based on the national energy policy established by the government and other related advisory agencies, including the Indonesian National Energy Council (DEN), and the parliament. According to the PLN's 2019-2028 plan, electricity produced from coal will still dominate the generation mix in Java-Bali (including insignificant share of Nusa Tenggara) in 2028 [29]. The mix will be coal (57.4%), followed by gas (24.6%) and combination of RE (17.6%), mainly consisting of hydro (6.5%) and geothermal (8.3%). The plan also suggests that significant development of RE-based capacity other than geothermal and hydro will not become priority despite the rapidly falling price of solar PV, an excellent solar resource, and some untapped wind generation potential.

While an electricity generation mix, mainly based on fossil fuels has been projected for the major grid systems in 2028, which satisfies the reserve margin target along with planning around RE-based capacity [29], the latest Indonesian electricity industry outlook indicates a different projection for 2050 in its Business as Usual (BAU) scenario [30]. Nationwide, RE technologies are expected to achieve 46.8% capacity share, followed by coal and gas with 27.6% and 25.5% capacity share, respectively [29]. Apart from these two contrasting projections, important indicators in the planning comprising both short and long-term system reliability are not well addressed. As also presented in the PLN's projection, the impact of available RE policy instruments on the future generation mix is arguably not well addressed. Furthermore, future uncertainty associated with, for example, the costs of different generation technologies and fuel resource availability is not assessed.

2.2. Coal domination among key challenges

Indonesia's electricity industry requires more attention from stakeholders and policymakers. PLN's financial limitations has been one of the barriers to planning for future generation mix. PLN is currently not financially viable due to the chronic and significant gap between its operating expenses, including high generation costs and debt on capital, compared to its operating revenue [31]. PLN (and hence the government) are also facing a serious risk of coal lock-in due to capacity obligation agreement to coal IPPs. Government electricity subsidies have been key to correcting PLN's financial circumstances and enabling the company to record positive yearly income.

Regulatory settings themselves do not always support to achieve the planning targets. As a result, the planning process is perceived as flawed for reasons including its lack of transparency, and the targets for capacity expansion are not being followed through [31]. For example, there is the apparent neglect of any meaningful strategy to incorporate increasingly cost-effective VRE options in the 2018-2027 plan [31]. Moreover, the plan includes only a minor role for solar PV despite global cost trends. While large-scale solar PV and wind are forecasted to be the most economic new-build options in near future and reshaping the generation mix in many emerging economies, it seems to currently be overlooked in Indonesia.

Indonesia's electricity generation mix has been dominated by coal as the country is one of the biggest coal producers and exporters in the world. Coal has been perceived as a cheap energy source for Indonesia because its externality cost in the long-term planning has not been considered. The government introduced coal price cap policy, currently set at US$ 70 per tonne, in addition to 25% domestic market obligation to keep electricity tariffs low and preserve its availability for domestic use [32]. As consequence, the competitiveness of solar and wind is weakened by this artificial pressure of domestic coal pricing. Under current economic circumstances, the burden of coal IPPs are rising as domestic coal demand is projected to increase due to additional coal-based generation capacity planned until the next decade.

Major key barriers to the transition from coal into large-scale adoption of VRE in Indonesia can be multi-dimensional, of which many of them are related to coal. These include a strong market position of coal, regulatory settings that support the coal industry, subsidies on electricity pricing and fossil fuels including Indonesia's coal price cap, an investment appetite for funding coal-fired power plants, avoidance of considering externality costs, unfavourable regulation on renewables, grid management challenges, and only limited political support for renewables, among other [33,34].

While Indonesia has committed to reducing its greenhouse gas emissions to 29% of the BAU level in 2030 or up to 41% with international assistance, the country requires more VRE especially solar and wind in addition to hydropower and geothermal. VRE progress has been recognized to be slower than planned. Solar PV and wind generation capacity were just below 0.1 GW in 2018, and their total additional capacity are planned only up to 0.9 GW and 0.85 GW in 2019–2028 plan. This is also an example of how the PLN 10-year plan for so many years has aimed at generation planning that shows a chronic reliance on 'artificially cheap' domestic coal amid the competitiveness of solar and wind in terms of both costs and emissions reductions.

This all suggests a need for more transparency/participation in planning by a wider range of stakeholders. Indonesia, and other jurisdictions with similar context, should rethink commitment to plants that involve rapid expansion of coal capacity given various international pressure and growing investor unwillingness to take on exposure to coal. Consequent with this, is a need to better understand the range of options, particularly with high RE penetrations, and their potential implications for both costs yet also reliability.

3. Method

Our study considers future electricity generation scenarios with high VRE penetrations, for Indonesia's Java-Bali grid capturing the complexities of Java-Bali solar and wind generation potential in terms of their hourly output variability and uncertainty (see Section 3.5 for more details), as well as Java-Bali hourly dynamic system demand (see Section 3.4 for more details) for a future year 2030. Appropriately capturing these dynamics in long-term generation planning, including renewables supply and system demand, requires use of a chronological dispatch model (tool).

We firstly use an open-source stochastic optimization tool (see Section 3.1 for more details) as a dispatch model to solve possible optimum (least-cost) generation portfolios and their parameters, subject on a range of system reliability targets and different carbon prices (CP) under high VRE penetrations. We particularly use two different approaches (hereafter methods) on how a wide range of reliability standards is put in the optimization (see further in Section 3.2). Techno-economic and demand data, and assumptions for our case study are also presented.

3.1. Simulation overview

We use an open-source evolutionary programming-based techno-economic optimization model, the National Electricity Market Optimiser (NEMO) [35] to obtain least-cost generation portfolios, including generation capacity mix, total generation cost, and CO_2 emissions, among other parameters. Fig. 1 shows the optimization framework and relationship between input-output in NEMO.

NEMO performs a stochastic optimization strategy, the Covariance Matrix Adaptation Evolution Strategy (CMA-ES), based on the evolutionary programming approach called Distributed Evolutionary Algorithms in Python (DEAP) [35]. In NEMO, the CMA-ES finds the least-cost capacity mix subject to several constraints and resource limitations, such as reliability standards, generators capacity build limit, and environmental factors including CP and emissions limit.

NEMO has been used in a diverse and growing number of studies on the electricity industry planning with high RE, including to find the least-cost 100% future renewable electricity system in Australia's National Electricity Market [37,38], and to compare the cost obtained by these systems with lower emissions fossil fuel-based systems, including gas and coal with carbon capture and storage [39], among others. NEMO also has been applied in some studies on Indonesia's Java-Bali grid future generation portfolios, such as to explore least-cost high RE portfolios using scenario analyses [40], to investigate the role of large-scale PV towards the least-cost systems given technology costs, demand levels, and fuel cost scenarios [41], and in a study on the key trilemma's metrics clustering based assessment of cost, security and environmental trade-offs considering possible future generation portfolios [36].

3.2. Methods for incorporating reliability in the optimization algorithm

Modelling long-term electricity industry planning for our study also requires inputting reliability of supply parameters. In this study, we use two different methods to represent reliability in the optimization algorithm. In the first method, reliability is represented as an optimization constraint by setting a certain value of USE applied for a whole year of simulated operation. We use the term USE to represent the level of grid reliability. It is expressed as a percentage of total unserved load over the total system demand in a year, given hourly traceable generation supply and demand resolution. Nevertheless, it should be noted that other reliability parameters might also be applied for electricity industry planning and operation purposes in different countries. We consider eight different USE limits, i.e. 0.005%, 0.05%, 0.5%, 1%, 2%, 3%, 4%, and 5%, and impose these fixed USE limits as hard maximum limits on the allowed USE.

Another approach is to place a typically very high penalty or 'Value of Lost Load' (VLL) price ($/MWh) to any USE so that the cost minimization sets USE at the efficient level where the cost of increasingly reliability is not worth the value of this reliability to end consumers. In practice, setting these reliability targets or penalty prices involves some sense of this trade-off between reliability and cost. In the second method, therefore, we apply different penalty costs/prices ($/MWh) for the USE. The purpose of applying this method is to provide an alternative way of getting the least-cost generation mix for different levels of reliability without having a predetermined USE constraint imposed into the simulations.

The reliability cost component represents the amount of cost $/MWh that is borne by the system as a penalty for not meeting a MWh demand. We effectively 'tune' this penalty charge through iterative runs of NEMO until we achieve delivered %USE outcomes equivalent to those we test (ranging from 0.005% to 5%) when setting this as a constraint.

While in this study we use %USE to represent the level of grid supply reliability in an hourly supply-demand resolution, it is calculated over the planning horizon, for example a certain year in the future. We do not assess or incorporate reserves margins (e.g.,

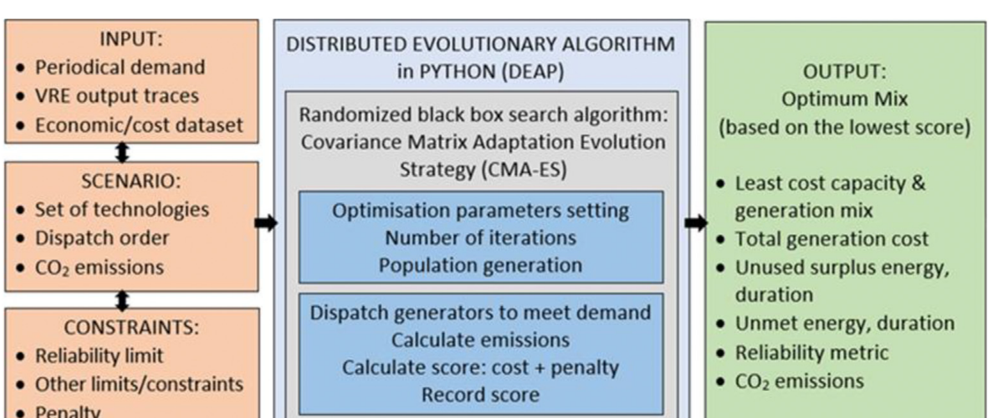

Fig. 1. The optimization framework and relationship between input -output in NEMO [36].

an operating reserve requirement of capacity above peak demand) into the analysis as is sometimes done in these types of studies. NEMO can actually model this and the implications of reliability level, as measured by USE target, on dynamic operating reserve margins are discussed in Tanoto et al. [42]. However, it lies beyond the scope of this study.

3.3. Scenarios, parameters, and assumptions

We consider different carbon prices (CP) as a proxy for a potentially wide range of policies that could deliver greater future VRE penetrations. Our chosen prices are \$0/tCO_2 (CP0), \$35/tCO_2 (CP35) and \$60/tCO_2 (CP60) – to reflect possible Indonesia's future policy settings on emissions reduction commitments, as well as also representing some other uncertainties around future fuel costs and cost for funding increasingly risky fossil fuel projects [40]. We use a 5% discount rate on annualized technology capital cost and a maximum permitted non-synchronous penetration of 0.75. Coal and gas prices are assumed at \$3.5/GJ and \$10.9/GJ, respectively, following [43].

Total industry generation costs are observed either in \$/total MWh of demand or \$/MWh of actual energy served, and according to the treatment of carbon revenue (CR) - included in total industry costs or not. In terms of analysis on emissions outcomes, we also use tCO_2/MWh energy served as an indicator to measure the environmental outcomes of different generation portfolios. We do not model transmission networks and other related investment requirements.

3.4. Demand data

Located in a tropical climate region with warm and humid air throughout the year, the Java-Bali region load profile is characterized by only small changes in terms of monthly highest and lowest hourly peak load. The dry season normally occurs around June to November followed by a wet season from December to May. Annually, minimum loads are mostly associated with the largest religious festivity periods in the country and extend over approximately a week or two before and after the observed day due to long holidays. This study uses 2015 hourly demand data of the Java-Bali grid [44] as a baseline, as shown in Fig. 2 (left). Besides, the highest and the lowest daily load profile are also shown in Fig. 2 (right).

We consider a single value of growth rate as this study focuses more on the solution space analysis of the results obtained from the least-cost mix simulation framework rather than just to compare optimal solutions of different demand scenarios. An arguably conservative linear annual growth rate of 5% is assumed in this study to create a projected 2030 demand profile based on the 2015 baseline, considering historical average annual growth in the region [36], yet also the slowing down of national economic growth in the past few years, unmet targets for national generation expansion and the uncertainty in the global future economic outlook and vulnerability of emerging economies against global energy commodities. As consequence, the modelling sees an energy demand profile of 346.5 TWh and 50 GW peak load by 2030.

3.5. RE generation potential data

We use the one-year of gridded hourly solar power output data for the same year (2015) from Renewables Ninja (RN), an online RE simulation tool [45]. By providing the tool with primarily a specific location and the tilt angle according to the location's latitude, the hourly time-step output of RN - based on 1 MW plant capacity - is modelled using the Global Solar Energy Estimator based on NASA MERRA2 direct and diffuse radiation and ground temperature data [45].

We follow the methodology used in the previous study [36,41], as up to 6 locations are assigned a PV plant candidate trace, one location in each province covered by the Java-Bali grid, considering factors such as high-capacity factor, low hourly temporal variability and low spatial variability in addition to the terrain and proximity with volcanoes. Hourly wind power output traces for selected locations for the year 2015 are obtained from RN as well. Locations assigned for wind plant candidates are chosen using the Indonesia wind prospecting map [46]. Despite the potential capacity of solar and wind mentioned for the Java-Bali grid in the literature [43,47,48], PV and wind build capacities are not capped in this study considering high uncertainty of their potential output. Meanwhile, build limits for geothermal and hydro are set at 10 GW and 8 GW, respectively, based on [43,47].

3.6. Technology costs data

We consider three fossil fuel-based technologies – coal fired power plant, combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT), and five candidates of portfolios from renewables,

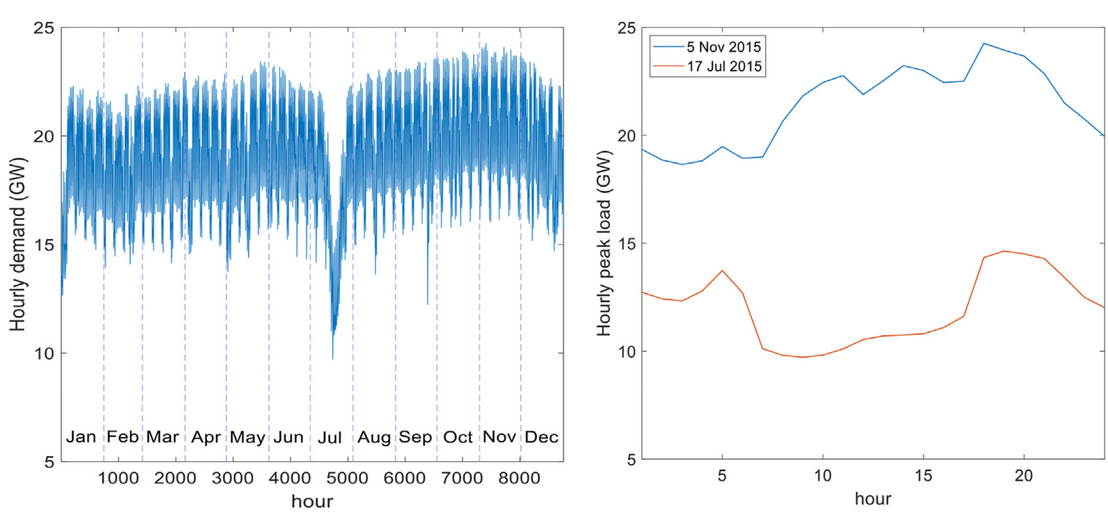

Fig. 2. The 2015 hourly demand of Java-Bali grid (left) and the corresponding highest and the lowest daily load profile (right).

Table 1
Mid-level 2030 technology cost components.

No.	Technology	Capital ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)
1.	Coal	1360	35.8	3.8
2.	OCGT	400	22.5	3.8
3.	CCGT	710	22.5	3.8
4.	Biomass	1600	43.8	6.5
5.	Geothermal (Geo)	3200	16.7	0.7
6.	Hydro	2000	35.8	3.8
7.	Wind onshore	1310	52	0.8
8.	Solar PV fixed	610	12.5	0.4

i.e., geothermal, hydropower, biomass, PV, and wind. We use mid-level 2030 technology costs scenarios, compiled from reports published by Indonesia National Energy Council [49,50] after further comparison and verification against other costs dataset [51–54]. The technology cost components used in this study are presented in Table 1 [36].

We are aware that the results presented in this paper, i.e., analysis around cost-reliability trade-offs and its implications toward the changes in capacity and generation mix depend greatly upon the technology costs assumed for this assessment. In recent years, the costs of some mature RE technologies such as PV and onshore wind have significantly decreased [55]. The current range of generation cost for fossil fuel capacity in Indonesia is about $75–150/MWh while weighted average levelized cost of electricity from major VRE technology such as wind onshore, hydro, and geothermal are already within that range, except for PV [43]. Therefore, significant changes in technology costs especially for RE could change the specific results of these analyses, mostly in terms of making VRE more attractive.

4. Results and discussions

In this section, we present and elaborate specific results for the Java-Bali grid case study. Initially, we show and describe results for the default case as shown in Section 4.1, followed by results on the possible optimum generation capacity portfolios, as obtained from the simulations using method 1 (Section 4.2) and method 2 (Section 4.3), and findings around CO_2 emissions outcomes (Section 4.4).

We model our future generation scenarios problem in two ways; first by treating USE in one set of modelling as an exogeneous constraint input, and then secondly as a cost associated with any USE. In this section we compare the results and computational ease of both approaches, while focussing on the actual reliability and cost trade-offs.

4.1. Default case

We first assess least cost 2030 Indonesia's Java-Bali generation portfolios as a default case by imposing a single fixed reliability constraint of 0.002% USE as our baseline scenario. We apply this relatively high reliability standard as it is currently the Australian National Electricity Market standard [17]. The generation technology candidates are shown in Table 1. We apply three-CP scenarios – no CP or CP0, $35/t$CO_2$ or CP35, and $60/t$CO_2$ or CP60. The optimum solutions are found for all CPs using NEMO as briefly described in earlier section. The least-cost capacity and generation mix of the default case with and without CPs are shown in Fig. 3.

The results highlight that while Geothermal and Hydro capacity hits its maximum allowed GW for all CP scenarios, the higher CP drives more PV (and at CP60 wind) as well as greater CCGT capacity additions. The share of RE including VRE in the generation mix increases from 54% to 64% and 71% in CP35 and CP60, respectively. On the other side, coal share decreases from 46% in CP0 to 33% and 18% in CP35 and CP60, respectively.

While imposing CPs would see higher generation costs due to the additional cost associated with cleaner technologies as well as the direct carbon cost, the collected revenue (CR) from imposing CPs can be used to provide cross-subsidies to groups of consumers who are most vulnerable to higher price of electricity due to this scheme and also for other social welfare purposes. Therefore, the total costs of industry excluding the carbon revenue (CR) are also

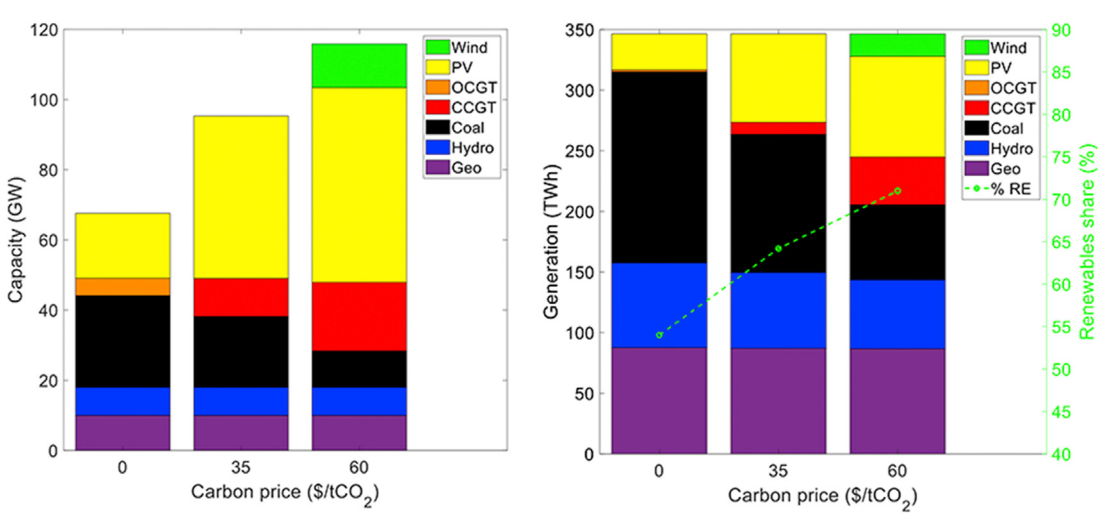

Fig. 3. Capacity (left) and generation mix (right) of the least cost default planning with CP0, CP35, and CP60.

Table 2
Total cost, simulated USE and VRE share using 0.002% USE as reliability constraint.

CP in $/tCO_2$	Total cost incl. CR in b$/year	Total cost excl. CR in b$/year	Simulated USE in percentage	VRE share in percentage
0	14.0	14.0	0.002	8.6
35	18.3 (30.7%[a])	14.3 (2.1%**)	0.002	21.0
60	20.9 (49.3%[a])	16.4 (17.1%**)	0.002	29.3

[a] Cost changes between the total cost obtained in the simulation involving CP35 and CP60 versus CP0; **Cost changes between total costs after taking carbon revenue out.

estimated. Variations in terms of the total cost exclude CR, simulated USE, and the share of VRE among the optimum capacity mixes for all CPs are presented in Table 2.

From Table 2, carbon revenue for CP35 and CP60 can be calculated to be b$4/year and b$4.5/year, respectively. Interestingly, almost doubling the CP has only a modest increase in carbon revenue given that it drives greater deployment of PV, wind, and gas generation. CO_2 emissions fall in CP35 and CP60 from 154 $MtCO_2$ in CP0 to 114 $MtCO_2$ and further to 76 $MtCO_2$, respectively.

As noted above, achieving a relatively high-reliability level is difficult in developing countries. Therefore, this study also considers lesser reliability standards to explore the optimum solution space in terms of a possible range of costs and acceptable reliability settings in the presence of high VRE penetrations. In following sections, we present results obtained from the simulations using two different methods in the optimizations, as described earlier.

4.2. Method 1: fixed USE limit

Considering a range of reliability levels, our assessment shows that, as expected, the total generation costs of the optimum (least-cost) portfolio mixes decrease as lower reliability standards imposed. In all simulations without CP, the total generation costs decrease from b$14/year to b$12.1/year, or a 13% reduction, associated to 0.005% USE and 5% USE, respectively. With the same reliability range, the costs in CP35 are reduced from b$18.4/year to b$16/year, or also a 13% reduction. In CP60, the costs are decreasing from b$20.9/year to b$18.2/year, also equivalent to a 13% reduction. Thus, all simulations produce around 13% cost reductions from the highest to the lowest reliability standards. It should be noted that CR is included in all results.

Fig. 4 (left) presents plots of the total generation costs, expressed in b$/year, for all optimum generation mixes versus USE for all CPs. Besides, it shows the cost trend if CRs are excluded from the total costs obtained in CP35 and CP60. A comparison between total generation costs, expressed in $/total MWh and $/MWh energy served versus USE is presented in Fig. 4 (right), either with or without CR embedded in the costs.

The fall in total industry costs through relaxing the reliability standard is significant in terms of total industry costs and average $/MWh costs. As expected, $/MWh-served cost reductions are less as USE increases given that less MWh are actually delivered. A higher difference between $/total MWh and $/MWh served is observed as reliability is further relaxed. Costs reduction expressed in b$/year and $/MWh served are presented in Table 3, highlighting relatively similar cost reductions across all the three CP scenarios.

For CP0, the total system cost decreases from b$14/year to b$12.1/year as USE limit drops from 0.005% to 5%. In other words, there would be around b$0.38/year on average that might need to be spent to increase the system reliability by 1%, with additional costs at around b$0.48/year and b$0.54/year for CP35 and CP60, respectively.

Fig. 5 shows the capacity and generation share of different technologies under different USE limits for CP0. PV capacity grows from 23 GW to 31 GW as reliability is relaxed to 5%. Coal capacity on the other hand reduces from 27 GW to around 18 GW. OCGT appears only in less than 0.05% USE which highlights the role of this peaking plant in meeting the rare peak times which could have been unserved with a lower reliability limit. In the generation mix (right figure), RE penetrations increase from 56.4% to 61.6%.

In simulations with CP35 (as shown in Fig. 6), some gas-based generation exist up to a 2% USE limit. At the USE target is relaxed, OCGT is displaced by CCGT then by VRE. Energy generation from coal is decreased around 22% and 20% at 0.005% and 5% USE limit,

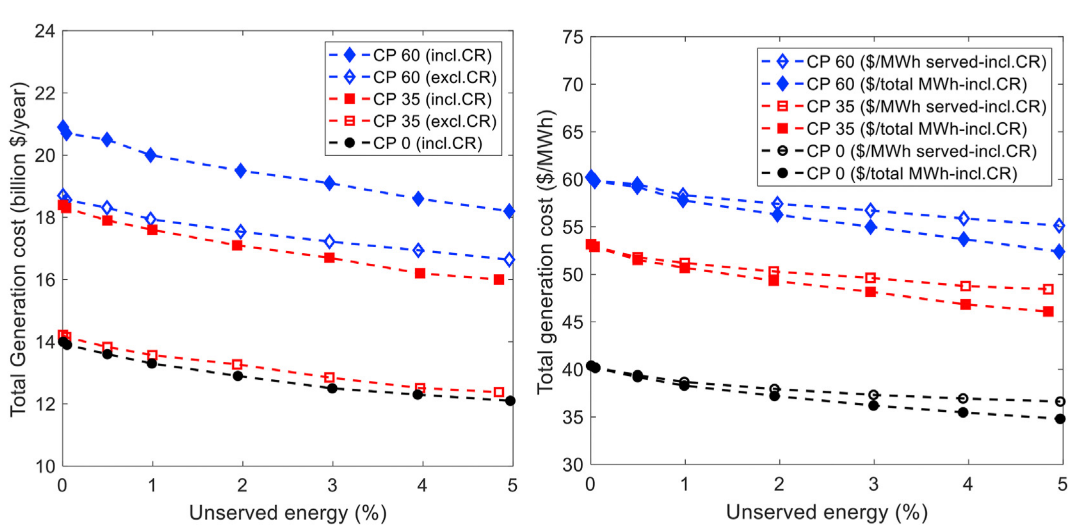

Fig. 4. Total generation costs versus realized USE, expressed in b$/year (left), and total generation costs versus realized USE, expressed in $/total MWh and $/MWh served (right), for all CPs.

Table 3
Cost for the highest and the lowest reliability level, expressed in \$/year and \$/MWh served.

CP (\$/tCO$_2$)	Cost incl. CRs (b\$/year)			Cost incl. CRs (\$/MWh served)		
	0.005% USE	5% USE	Cost reduction (%)	0.005% USE	5% USE	Cost reduction (%)
0	14.0	12.1	13.5	40.39	36.62	9.3
35	18.4	16.0	13.0	53.17	48.44	8.9
60	20.9	18.2	12.9	60.24	55.13	8.5

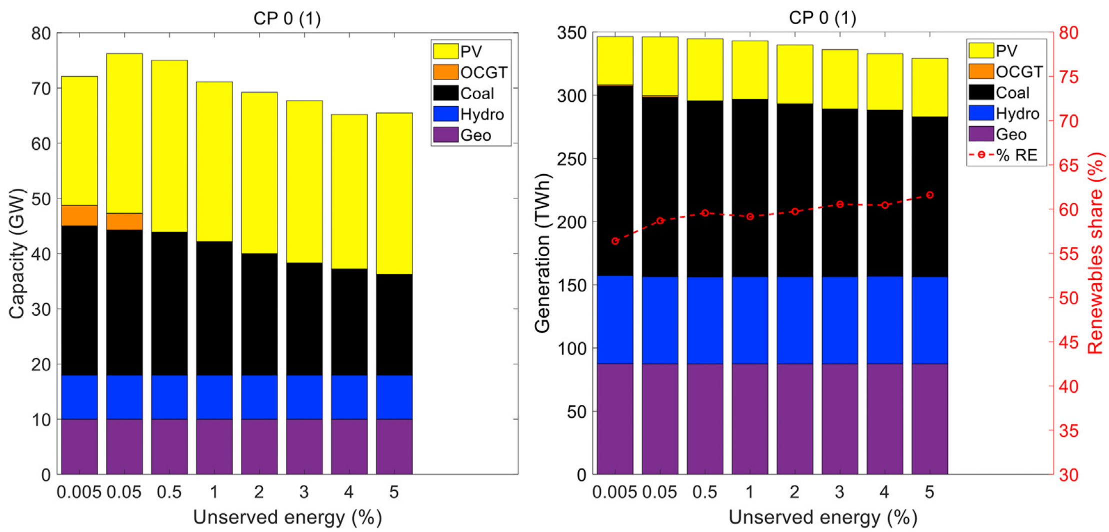

Fig. 5. (Left) Capacity mix and (right) corresponding generation mix and the trend of RE share of the optimum future mix by allowing different USE limits imposed as reliability constraint and CP0.

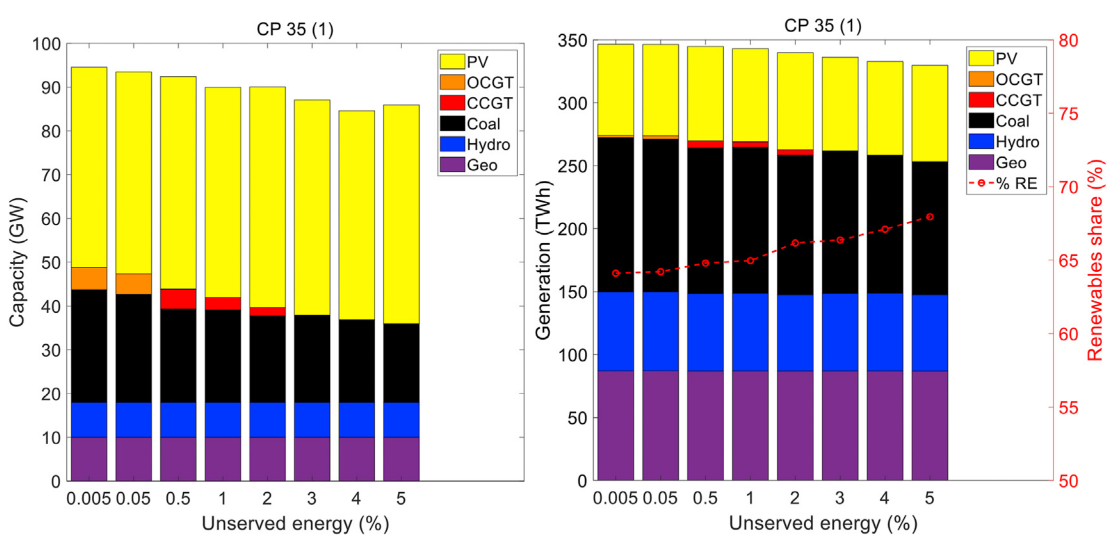

Fig. 6. (Left) Capacity mix and (right) corresponding generation mix and the trend of RE share of the optimum future mix by allowing different USE limits imposed as reliability constraint and CP35.

respectively. A higher capacity of PV is obtained at this CP compared to CP0. For 0.005% and 5% USE limit, PV capacity reaches 45.78 GW and 49.97 GW, respectively. As seen in Fig. 6 (right), RE shares for the highest to the lowest reliability range from 64.11% to 67.95% while VRE shares are 20.87% at 0.005% USE limit and increase up to 23.17% at a 5% USE limit.

In CP60, the majority of coal capacity in the optimum mixes across all reliability standards are replaced by CCGT, in addition to extensive solar and wind penetrations. We find a relatively similar PV capacity of 50 GW for all reliability levels while wind capacity doubles from 14.4 GW at 0.005% USE limit to 31.8 GW at a 5% USE limit, while coal capacity exist only at 0.005% and 0.05% USE limit. As depicted in Fig. 7 (top), RE generation shares increase roughly 10.5% from 0.005% to 5% USE limit.

4.3. Method 2: priced USE

In this section we present findings obtained using method 2 and their comparison with those revealed from simulations using method 1. To permit comparison we tune the penalty price on USE $/MWh so that the optimization delivers the USE targets used in method 1. For example, the realized cost of USE of $68/MWh delivers 5% USE. The tuned costs of USE along with the corresponding USE levels are shown in Fig. 8 (left). For generation costs with CR included, the costs obtained from method 2 are similar to those using method 1 when excluding the realized penalty cost component. A comparison between generation costs obtained from both methods is presented in Table 4.

Results obtained from the simulations using method 2 without CP are presented in Fig. 8 as an example for comparison purposes against method 1 (results for CP35 and CP60 are shown in the appendix).

Our analysis shows that NEMO was able to solve the same costs and generation mix modelling reliability through either a fixed USE constraint or by pricing USE in the cost minimization function. As noted in Section 3.2, this involved a 'tuning' process where we ran NEMO with different penalty costs ($/MWh) until it delivered USE% broadly equal to the range of USE we tested using the constraint approach. The penalty price approach does have one particular advantage for evolutionary computation, where hard constraints can cause challenges for the evolutionary process in trying to get as close as possible to, while not exceeding, this reliability target. As shown in Fig. 8, this method tends to provide a smoother trend of capacity mix outputs. Still, similar results of RE generation shares in the optimum generation mixes using method 1 and method 2 are achieved, as shown in Table 5.

Given the easier and more stable computation using penalty pricing rather than hard constraints, our findings suggest that it might be the preferred approach for modelling reliability and cost trade-offs with evolutionary programming. Other solution approaches such as LP may of course exhibit different behaviour across these two approaches.

4.4. CO_2 emissions outcomes

Total CO_2 emissions obtained from method 2, expressed in $MtCO_2$ and tCO_2/MWh served, across simulated reliability standards are shown in Fig. 9. The total amount of CO_2 emissions in CP0 is decreased from 146.4 $MtCO_2$ at 0.005% USE limit to 122.2 $MtCO_2$

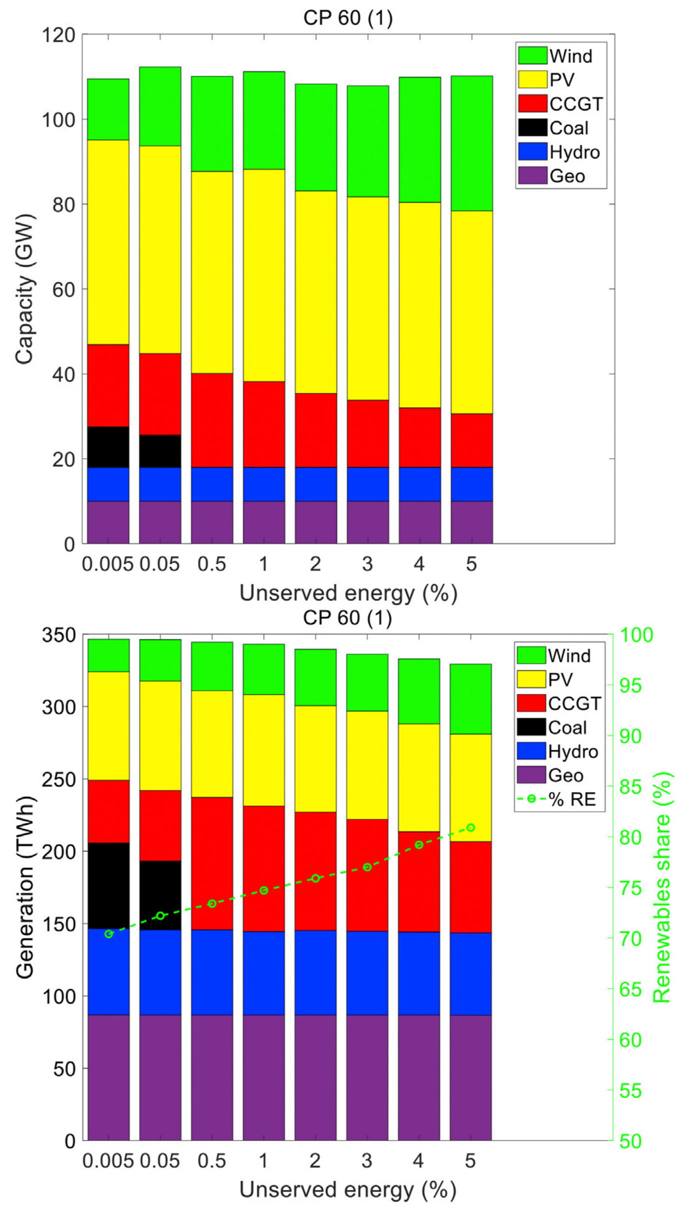

Fig. 7. (Top) Capacity mix and (bottom) corresponding generation mix and the trend of RE share of the optimum future mix by allowing different USE limits imposed as reliability constraint and CP60.

at 5% USE limit which is around 16.5% decrease. CP35 scenario shows a similar level of emissions reduction in terms of percentage from 120.2 $MtCO_2$ to 102.4 $MtCO_2$.

The downtrend of the total emissions due to larger USE level is shown by the dashed black lines. A significant drop in CO_2 emissions is obtained in CP60 from 72.9 $MtCO_2$ to 26.2 $MtCO_2$, equivalent to a 64% drop. A similar declining trend is also observed in tCO_2/MWh energy served (dashed-red lines), suggest how reducing reliability requirements not only reduces total and $/MWh industry costs but also CO_2 emissions. The largest reduction is obtained for CP60, in which CO_2 emissions are falling from 0.21 tCO_2/MWh to

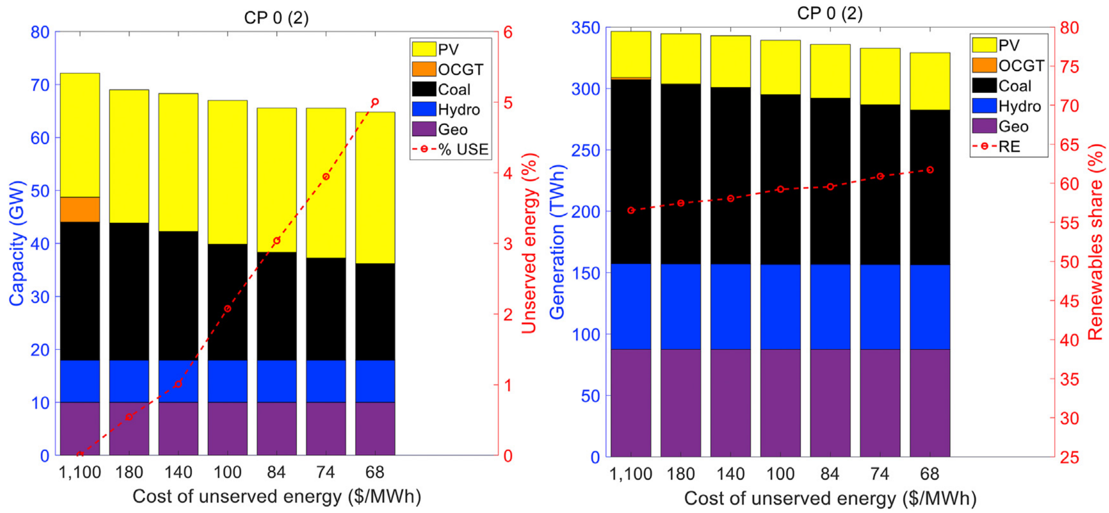

Fig. 8. (Left) Least cost capacity mix and corresponding USE and (right) least-cost generation mix and RE shares for CP0.

Table 4
Comparison of generation cost of the least cost portfolios mix including CR (in b$/year).

USE level (%)	Method 1			Method 2[a]		
	CP0	CP35	CP60	CP0	CP35	CP60
0.005	14.0	18.4	20.9	14.0	18.4	20.8
0.5	13.6	17.9	20.5	13.5	17.8	20.3
1	13.3	17.6	20.0	13.3	17.5	19.9
2	12.9	17.1	19.5	12.8	17.0	19.4
3	12.5	16.7	19.1	12.5	16.6	18.9
4	12.3	16.2	18.6	12.3	16.2	18.5
5	12.1	16.0	18.2	12.0	15.8	18.1

[a] Realized penalty cost component is excluded. The total cost of the industry and penalty cost component is presented in Appendix (Table A).

Table 5
Comparison of RE generation shares in the optimum generation mixes (in %).

USE level (%)	Method 1			Method 2		
	CP0	CP35	CP60	CP0	CP35	CP60
0.005	56.4	64.1	70.4	56.5	64.0	70.6
5	61.6	68.0	80.8	61.7	67.9	80.1

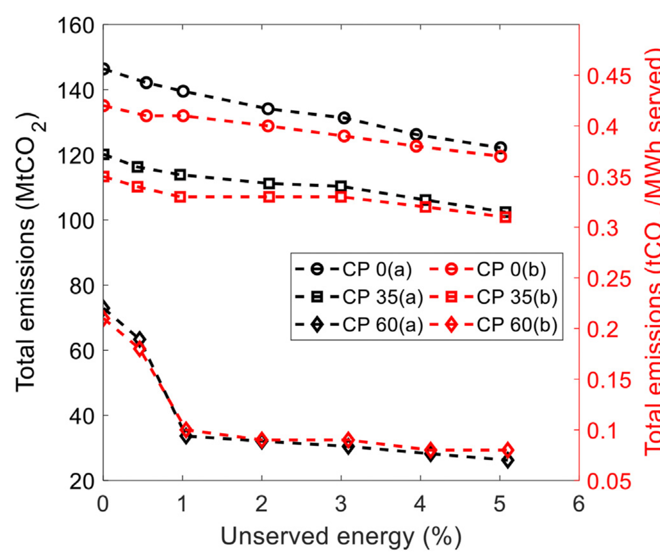

Fig. 9. Total CO_2 emissions of least-cost mixes (dashed-black colour lines), and CO_2 emissions per MWh served (dashed-red colour lines) versus realized USE for all CPs using method 2. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

0.08 tCO_2/MWh, or around 62%.

In summary, our modelling results suggest that using lower reliability standards in generation planning might not only reduce total $/year and average $/MWh industry costs, but it can also facilitate greater VRE deployment and consequent emissions reductions. Imposing a CP can also greatly reduce emissions and the industry cost increases may not be as significant as feared as long as the special nature of carbon revenues are appropriately factored into the analysis. The emission outcomes of Fig. 9 highlight the potentially major opportunity to deliver much lower industry emissions through CP and more relaxed reliability standards.

5. Conclusions

Electricity industry planning in emerging economies is an enormously challenging task given the need to meet growing demand despite challenges in financing investment. Poor reliability outcomes often result, while adverse environmental impacts are, understandably, not given great weight. Wind and solar PV offer extraordinary potential to assist these electricity industries to meet growing demand at reasonable cost whilst greatly improving environmental outcomes.

Our study provides new perspectives on these challenges by exploring the implications of different reliability standards, including relatively high USE, on generation costs for future electricity generation mixes with high VRE scenarios. While we undertake long-term planning, we also model variable wind and solar generation with very high temporal (hourly) and locational (choosing traces from a range of solar and wind locations) fidelity. Our methods compare different reliability outcomes through imposing reliability as a constraint versus applying different prices on any USE. We also consider the use of carbon pricing to encourage higher RE penetrations and utilize 'shadow' externality pricing and hence 'revenue' flows in our analysis.

While the broad topic of reliability-cost trade-offs for future electricity generation scenarios has, of course, already received considerable attention in the literature, reliability targets has typically been fixed at very high levels in electricity generation planning exercises. In addition to imposing reliability as a constraint, our study explicitly prices the impacts of different reliability targets, in the context of emerging economies where electricity industry reliability is often significantly lower than that achieved in industrialized economies, and with high VRE penetrations. Our study brings together two broad issues, i.e., appropriate operational reliability standards and the complexities of high VRE penetrations in the context of emerging economies' electricity industry planning.

We applied these methods to assess possible optimum generation capacity portfolios for different reliability levels and CPs for the Java-Bali grid. The simulation results using both reliability methods exhibit similar results in terms of increasing penetration of RE, including VRE, notable reduction in total generation costs, and a wide span of CO_2 emissions reduction, although placing reliability in the cost function rather than constraint set would seem to offer computational advantages.

Our results show a similar 5%–10% increased renewables share as CP increases by relaxing the reliability target from 0.005% USE to 5% USE. The least cost generation mix has 60%, 68%, and 80% renewables share at 5% USE for CP0, CP35, and CP60, respectively. Meanwhile, cost reductions (in $/year includes carbon revenue) of around 13% are obtained across all CP scenarios when shifting from 0.005% USE to 5% USE in the first method. This equivalents to a cost reduction of around 9% in $/MWh served. While CO_2 emissions reductions from greater VRE deployment are seen as %USE increases, imposing CP can significantly help to further reduce total CO_2 emissions in terms of both $MtCO_2$ and tCO_2/MWh served.

We do not conclude that emerging economies should target lower reliability levels than industrialized economies. However, we do highlight the potentially significant overall industry cost reductions associated with lower reliability targets. Future work is, however, required to better understand the implications of this for electricity consumers in emerging economies, noting that they generally experience far lower reliability than consumers in industrialized economies.

Our study also does not explicitly model system flexibility beyond the generation mix service a year of simulated hourly demand. Still, the resulting generation mixes feature significant gas-fired generation which can flexibly respond to changing VRE availability [41].

While our specific findings are relevant to the Java-Bali electricity grid, the approaches used in this study have broader relevance for electricity industries in other jurisdictions given similar contexts, particularly for planners and policymakers in examining the impact of different reliability settings on the economics of different generation capacity expansion pathways. A more flexible approach to reliability targets not only can reduce total generation costs but also support greater use of VRE technologies.

CRediT author statement

Yusak Tanoto: Conceptualization, Methodology, Software, Formal analysis, Visualization, Writing – Original Draft. **Navid Haghdadi**: Visualization, Software, Writing – Review & Editing. **Anna Bruce**: Writing – Review & Editing, Supervision. **Iain MacGill**: Writing – Review & Editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix

Table A
Total cost of industry and penalty cost of the least-cost mix using method 2 (in b$/year)

USE level (%)	CP0		CP35		CP60	
	Total cost	Penalty	Total cost	Penalty	Total cost	Penalty
0.005	14.0	0.02	18.5	0.02	20.9	0.03
0.5	13.8	0.34	18.1	0.27	20.7	0.37
1	13.7	0.49	18.0	0.50	20.6	0.62
2	13.5	0.72	17.9	0.97	20.4	0.97
3	13.4	0.88	17.8	1.20	20.3	1.39
4	13.3	1.01	17.6	1.49	20.3	1.79
5	13.2	1.18	17.6	1.81	20.2	2.19

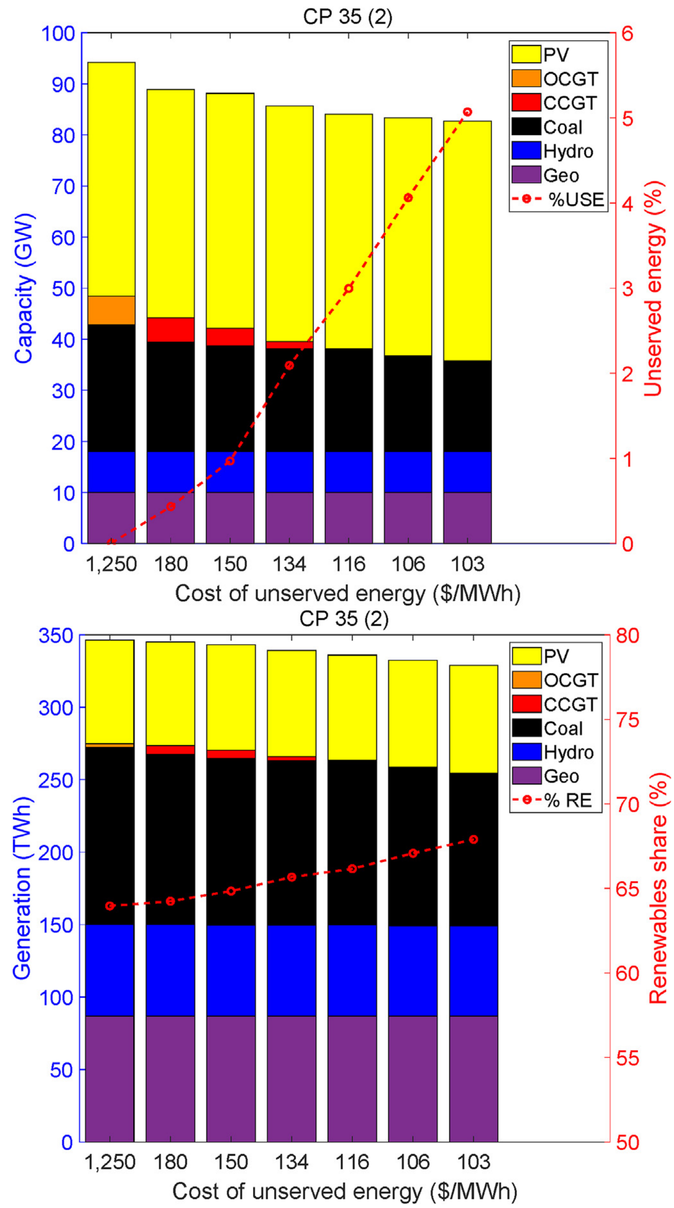

Fig. A. (Top) Least cost capacity mix and corresponding USE and (bottom) least-cost generation mix and RE shares for CP35.

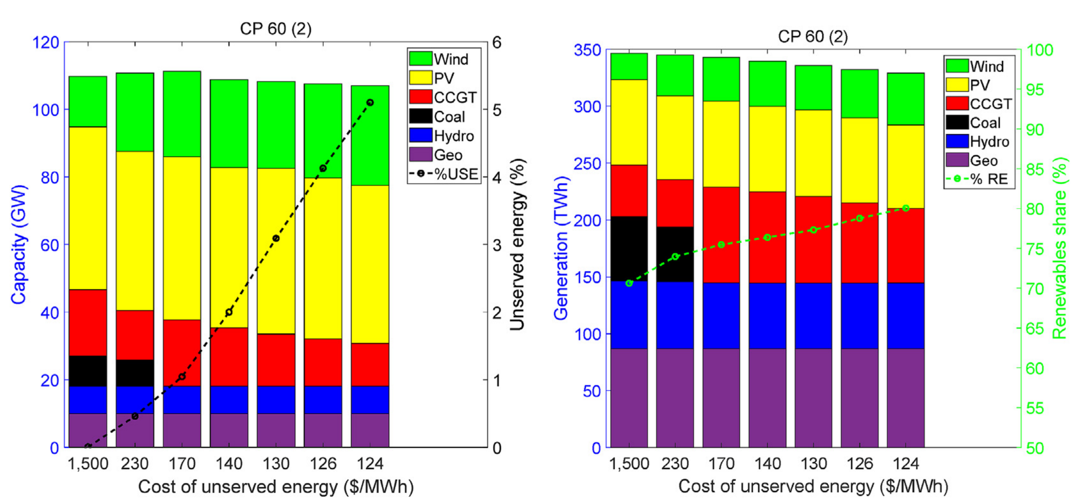

Fig. B. (Left) Least cost capacity mix and corresponding USE and (right) least-cost generation mix and RE shares for CP60.

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