Delft University of Technology

# Geospatial analysis of Indonesia's bankable utility-scale solar PV potential using elements of project finance

Langer, J.K.A.; Roosenboom-Kwee, Z.; Zhou, Y.; Isabella, O.; Ashqar, Ziad; Quist, J.N.; Praktiknjo, Aaron; Blok, K.

**DOI**
10.1016/j.energy.2023.128555

**Publication date**
2023

**Document Version**
Final published version

**Published in**
Energy

**Citation (APA)**
Langer, J. K. A., Roosenboom-Kwee, Z., Zhou, Y., Isabella, O., Ashqar, Z., Quist, J. N., Praktiknjo, A., & Blok, K. (2023). Geospatial analysis of Indonesia's bankable utility-scale solar PV potential using elements of project finance. *Energy*, *283*, Article 128555. https://doi.org/10.1016/j.energy.2023.128555

**Important note**
To cite this publication, please use the final published version (if applicable).
Please check the document version above.

**Copyright**
Other than for strictly personal use, it is not permitted to download, forward or distribute the text or part of it, without the consent of the author(s) and/or copyright holder(s), unless the work is under an open content license such as Creative Commons.

**Takedown policy**
Please contact us and provide details if you believe this document breaches copyrights.
We will remove access to the work immediately and investigate your claim.

*This work is downloaded from Delft University of Technology.*
*For technical reasons the number of authors shown on this cover page is limited to a maximum of 10.*

Energy 283 (2023) 128555

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

# Geospatial analysis of Indonesia's bankable utility-scale solar PV potential using elements of project finance

Jannis Langer [a,*], Zenlin Kwee [b], Yilong Zhou [c], Olindo Isabella [c], Ziad Ashqar [a], Jaco Quist [a], Aaron Praktiknjo [d], Kornelis Blok [a]

[a] Delft University of Technology, Faculty of Technology, Policy and Management, Department of Engineering Systems and Services, Jaffalaan 5, 2628 BX, Delft, the Netherlands
[b] Delft University of Technology, Faculty of Technology, Policy and Management, Department of Values, Technology and Innovation, Jaffalaan 5, 2628 BX, Delft, the Netherlands
[c] Delft University of Technology, Faculty of Electrical Engineering Mathematics and Computer Science, Department of Electrical Sustainable Energy, Photovoltaic Materials and Devices Group, Mekelweg 4, 2628 CD, Delft, the Netherlands
[d] RWTH Aachen University, Chair for Energy System Economics, Institute for Future Energy Consumer Needs and Behavior, E.ON Energy Research Center, Mathieustraße 10, 52074, Aachen, Germany

ARTICLE INFO

Handling editor: Soteris Kalogirou

*Keywords:*
Solar PV
Geospatial analysis
Project finance
Economic analysis
Indonesia
Monte Carlo simulation

ABSTRACT

Geospatial analysis is useful for mapping the potential of renewables like solar PV. However, recent studies do not address PV's bankable potential for which project financing can be secured. This paper proposes a framework that incorporates project finance into geospatial analyses to obtain the bankable potential of renewables. We demonstrate our framework for Indonesia, and compare the bankable potential with the socio-economic potential mostly used in literature. Using average inputs On average, the technical potential is 12,200 TWh/year and the socio-economic potential is 152.7 TWh/year if capped by 2030 demand (34% coverage). Considering PV's financing risks, PV's bankable potential is 16.0 TWh under current conditions if capped by 2030 demand (3.6% coverage). Both economic potentials are mainly in East Indonesia and absent on Java due to tariffs and land availability. For the bankable potential, the risk perception by banks and investors is another key influence. With a feed-in tariff of 11.5 US¢(2021)/kWh and temporary lift of import restrictions, the bankable potential is 23 TWh if capped by 2030 demand (5.2% coverage) and spreads to Java. For more widespread bankability, additional temporary measures are recommended until the PV's costs have decreased further and trust by financial institutions has increased.

Symbols

| Symbol | Meaning | Unit |
|---|---|---|
| *AEP* | Annual electricity production | kWh/year |
| *BPP* | Biaya pokok penyediaan (basic costs of electricity provision) | US¢(2021)/kWh |
| *CAPEX* | Capital expenses | US$(2021) |
| *CRF* | Capital recovery factor | – |
| *DSCR* | Debt service coverage ratio | – |
| *IRR* | Internal rate of return | % |
| *LCOE* | Levelized cost of electricity | US¢(2021)/kWh |
| *NPV* | Net present value | US$(2021)/$kW_p$ |
| *OPEX* | Operational expenses | US$(2021)/year |
| *p* | Local electricity tariff | US¢(2021)/kWh |
| $P_{peak}$ | Installed peak power | $kW_p$ |
| *T* | Project lifetime | years |
| *WACC* | Weighted average cost of capital | % |

* Corresponding author.
*E-mail address:* j.k.a.langer@tudelft.nl (J. Langer).

https://doi.org/10.1016/j.energy.2023.128555
Received 21 February 2023; Received in revised form 22 June 2023; Accepted 24 July 2023
Available online 26 July 2023
0360-5442/© 2023 The Authors. Published by Elsevier Ltd. This is an open access article under the CC BY license (http://creativecommons.org/licenses/by/4.0/).

**Table 1**
Overview of peer-reviewed journal articles using geospatial analysis to determine the economic PV potential. For currency conversion to [US¢(2021)/kWh], we use the rates in Supplementary Material C and assume the year of publication as the original currency value. PBP: payback period.

| Ref | Location | Economic metric | Discount rate | LCOE (original unit) | LCOE [US¢ (2021)/kWh] | Benchmark (original unit) | Uncertainty studied? |
|---|---|---|---|---|---|---|---|
| [7] | India | LCOE | 10% | 51.6–89 US$/MWh | 5.2–9.0 | – | – |
| [8] | Morocco | LCOE | 5% | 0.0331–0.0618 US $/kWh | 3.3–6.2 | LCOE = 0.0365 US$/kWh | – |
| [9] | Mexico | LCOE | 8% | 23–35 EUR/MWh | 2.8–4.2 | LCOE ≤ 0.07 EUR/kWh | – |
| [10] | Fujian, China | LCOE, NPV, PBP | 8% | 0.16–0.27 US $/kWh | 18.2–30.8 | NPV > 0 US$ | Sensitivity analysis (performance ratio, rooftop-to-built-up-area ratio, popularizing ratio) |
| [11] | West Kalimantan, Indonesia | LCOE | – | 4.47–5.46 US ¢/kWh | 4.5–5.5 | Average cost of other generation technologies | – |
| [12] | China | LCOE | 9% | 0.12–6.2 US$/MJ | 43.2–2,230 | – | – |
| [13] | Jordan | LCOE, NPV, PBP | 5% | 0.025–0.0477 US $/kWh | 2.5–4.8 | LCOE ≤ 0.05 US$/kWh | – |
| [14] | Chile | LCOE, NPV, IRR | 5% | – | – | IRR ≥ Required rate of return | Sensitivity analysis (CAPEX, discount rate) |

## 1. Introduction

### 1.1. Geospatial analysis and renewable energy potentials

Geospatial analysis is useful for mapping the potential of renewables, like solar PV. With this method, sites suitable for deployment are detected by filtering out areas where the studied technology cannot be implemented, e.g. nature conservation zones. What "suitable" means depends on the type of potential; and most commonly they are classified as theoretical, technical, and economic potential in literature [1–3]. The theoretical potential comprises the primary energy content of the resource (e.g. solar irradiation) considering only physical constraints. The technical potential is the part of the theoretical potential after conversion to a secondary energy carrier (e.g. electricity) given practical constraints, e.g. conversion efficiency and land use. The economic potential is the economically attractive part of the technical potential and can be assessed from a socio-economic or private perspective. In this paper, we will determine the socio-economic potential, but our focus will be on what we call the 'bankable potential'. From the private investor perspective, the key challenge is to secure funding for a project and make it sufficiently profitable. The bankable potential is defined as the part of the technical potential that satisfies these conditions from the perspective of a private investor.

Potentials provide a useful benchmark to gauge the progress of renewable energy implementation. In 2022, for example, only 1.3 PWh of the global technical PV potential of 207,500 PWh/year [4] has been implemented, generating 4.5% of global 2022 electricity production [5]. Hence, we might still only be at the inception of PV's global spreading despite its rapid growth in the last decades [6]. Geospatial analysis can show where technically feasible sites for further PV capacity are located, and how their economic potential can be lifted.

### 1.2. Overview and limitations of economic PV potential literature

Table 1 lists current studies that use geospatial analysis to investigate PV's economic potential.[1] The standard approach in literature is to first map the technical potential across the studied region, either with [7–12] or without [13,14] exclusion criteria. Then, one or several economic metrics are calculated, most commonly the *Levelised Cost of Electricity (LCOE)*, *Net Present Value (NPV)*, and payback period.

Regarding the technical potential, PV's overall technical potential is commonly found to be large, but spatially heterogeneous due to locally varying resource availability and land use constraints, amongst others. Regarding the economic potential, recent studies found LCOEs below 10 US¢(2021)/kWh for regions across the world. However, direct comparisons between studies are difficult due to different economic assumptions, inclusion of supplemental technologies like energy storage [13], and the use of future instead of present costs [9].

Although current studies provide useful insights into PV's technical potential and LCOEs, we detect five limitations. First, only one study [10] includes private economic aspects like tax expenses. This implies that current literature mainly focusses on socio-economic and less on bankable potentials, thus disregarding actors taking the risk of financing PV projects. Second, only three studies [9,10,13] report the economic potential in terms of electricity production. Consequently, it is unclear from most studies how much present and future demand can be covered economically. Third, only one study [9] fully discloses the sources for and rationale behind economic inputs like the discount rate. Therefore, it cannot be validated whether the inputs are up-to-date and practically relevant. Fourth, only two studies [10,14] assessed the sensitivity of their results to changes in inputs, and no study incorporated the uncertainty of inputs directly into their analysis. Fifth, contemporary economic analyses merely provide snapshots under current conditions as only one study explored policy-support options, like feed-in tariffs [10], to enhance the economic potential.

### 1.3. How project finance could address PV literature's limitations

Incorporating project finance into geospatial analyses could address the five limitations above. Project finance is an increasingly popular way of financing renewable energy infrastructure [15]. Here, we provide a brief overview [15–19] of project finance, accompanied by commonly used methods and relevant contemporary literature.

In the beginning, there is a party of companies that wants to develop a PV plant. With project finance, these companies create a new, self-contained company (typically a joint venture) with the sole purpose of realising and operating the project. The project is usually financed via two sources of funding, namely equity and debt. Equity is provided by the shareholders, or *sponsors*, of the project and includes the companies behind the joint venture, and passive investors like investment funds.

Sponsors decide whether to invest based on the expected returns, which must cover the cost of equity plus a risk premium, e.g. 10% [17]. For that, the project's cash flow and its uncertainty under the current policy environment (e.g. subsidies and tax credits) must be thoroughly understood. In literature, these are commonly determined via cash flow analysis and Monte Carlo simulation [19–21], with which calculations are performed repeatedly with randomised inputs. From the resulting distribution of outputs, the exceedance probability can be derived via pX values [18,19,21]. A p90 value, for example, is the value that is

[1] See Supplementary Note A for the search queries and sampling methodology. For explanations of the economic and financial terms used in this paper, see the glossary in Supplementary Note B.

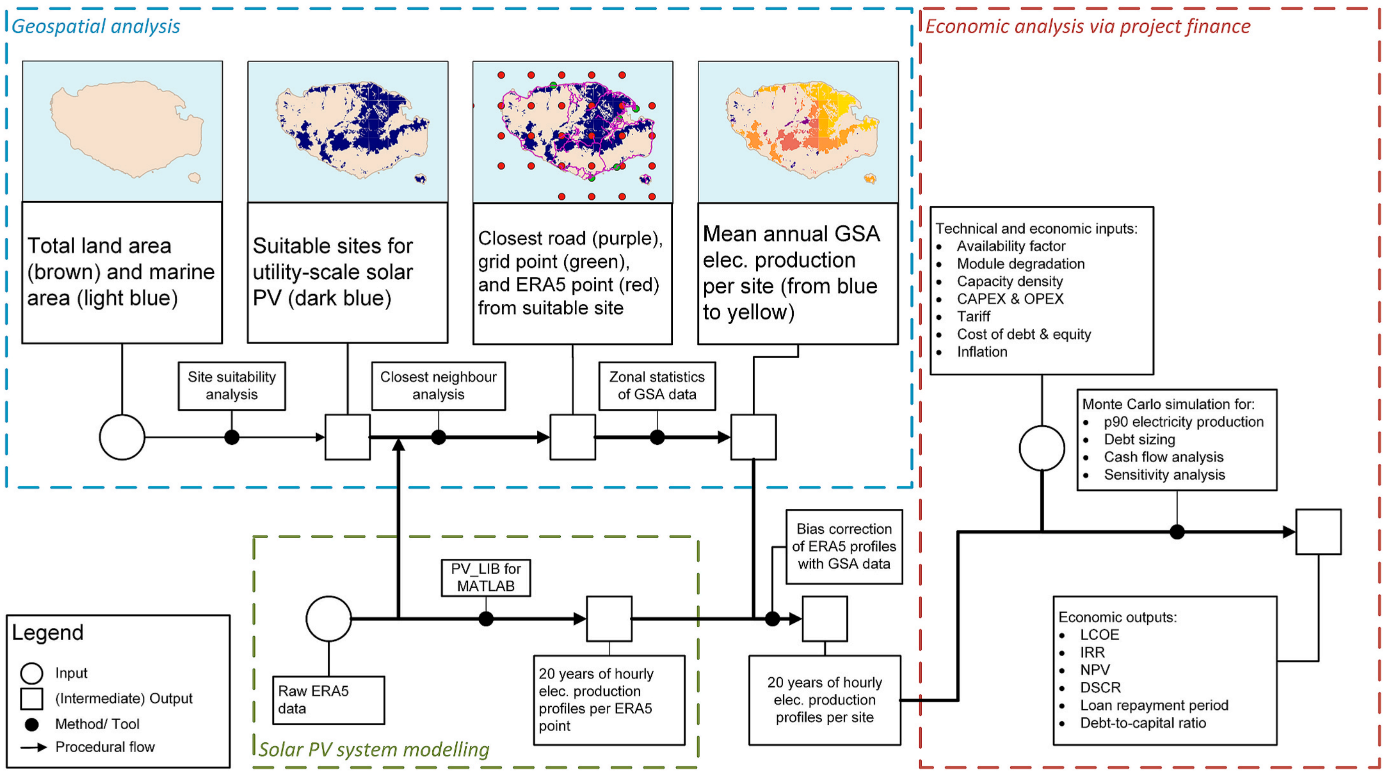


**Fig. 1.** Overview of the framework presented in this study.

exceeded by 90% of the total sample. In solar energy literature, the irradiation and plant's productivity have been randomised [19,22,23], but inputs like *Capital Expenses (CAPEX), Operational Expenses (OPEX),* and income have not.

Although solar projects can be funded solely with equity, it is favourable to partially fund the project via debt, which is generally cheaper than equity. Therefore, the project developers approach *lenders*, like banks, and request the debt in the form of loans. Lenders may agree to provide the debt if the project's estimated cash flows are high enough to repay the loan based on a set of requirements, e.g. a *Debt Service Coverage Ratio (DSCR)* of at least 1.3, a loan repayment period between 8 and 18 years, and a maximum debt-to-capital ratio of 70% at the given interest rate [17]. The DSCR is the ratio between available cash flow and debt repayment obligation and ensures sufficient cash flows for debt service. The debt-to-capital ratio is the share of debt to the sum of debt and equity, i.e. capital, and reflects the project's dependency on debt.

Sponsors and lenders might evaluate the same project's economic attractiveness differently, and their assumptions might only align after several back-and-forth discussions. Throughout this iterative process, lenders can adjust parameters like DSCR, loan repayment period, and interest rate to optimise the debt. If the project is still bankable after sponsors and lenders agree on the inputs, they sign a contract that settles, amongst others, the amount of debt, the repayment schedule, and penalties for breach of contract. A project is considered bankable (and part of the bankable potential) if such agreement can be reached, satisfying the requirements of both sponsors and lenders.

**Table 2**
Site selection criteria used in this research. Unless stated otherwise, the land use data originates from Ref. [28].

| Exclusion group | Exclusion layers [Ref] | Layer type + Resolution | Threshold/ Buffer |
|---|---|---|---|
| Geography | Slope [29] | Raster, 463 m | Slope ≥15° |
| | Volcano [30] | Vector | 2,000 m |
| Water bodies/wetlands (buffers from Refs. [7, 31]) | Water bodies | Vector | 300 m |
| | Fish pond | Vector | 300 m |
| | Swamp/swamp shrub | Vector | 300 m |
| | Coastline | Vector | 300 m |
| | Mangrove forest | Vector | 300 m |
| | Swamp forest/ peatlands [32] | Vector | 300 m |
| Built-up infrastructure (buffers from Ref. [9]) | Settlements | Vector | 200 m |
| | Transmigration area | Vector | 200 m |
| | Airports/harbours [33] | Point + Vector | 3,000 m |
| Agriculture | Dryland agriculture | Vector | – |
| | Estate crop plantation | Vector | – |
| | Shrub-mixed dryland farm | Vector | – |
| | Mining area | Vector | – |
| | Rice field | Vector | – |
| Forestry | Plantation forest | Vector | – |
| | Primary and secondary dryland forest | Vector | – |
| Conservation (buffers from Ref. [9]) | Nature conservation zones [34] | Vector | 1,000 m |

### 1.4. Scope, objectives, and outline of the paper

This paper proposes a framework that incorporates elements of project finance into geospatial analyses to map the bankable potential of renewables. We demonstrate our framework for land-based, utility-scale PV in Indonesia, a country rich in solar resources [24], but slow in implementation [25] due to suboptimal financing conditions, amongst others [26]. We define utility-scale PV as plants with a installed peak power of at least 1 $MW_p$.

First, we map the technical potential using a set of exclusion criteria. Then, we calculate the socio-economic potential and bankable potential using our framework. For the latter, we use a debt sizing and cash flow analysis model to calculate a set of metrics commonly used in project finance based on literature and expert elucidation. We assess the metrics' uncertainty via Monte Carlo and sensitivity analysis. Using these metrics, we calculate PV's bankable potential under current and policy-

**Table 3**
Technical and economic assumptions for parameters and their uniformly distributed ranges. DC-side efficiency includes soiling and cable losses (spectral mismatch and angle-of-incidence losses are calculated hourly), while AC-side efficiency includes inverter, transformer, cable, and availability losses. If no reference is provided, the parameter was estimated by the authors. "Personal communication" refers to the expert elucidation done for this research.

| Parameter | Assumption | Reference(s) |
|---|---|---|
| **Technical solar PV parameters** | | |
| PV module manufacturer and name | Canadian Solar Inc. CS1U–400MS | CEC Module Database from PV_LIB [38] and manufacturer datasheet [39] |
| Peak power module [$W_p$] | 400 | |
| Module area [$m^2$] | 1.99 | |
| Material | mono-Si | |
| Module tilt [°] | *latitude* × 0.87 | [40] |
| Albedo coefficient | 0.25 | [41] |
| DC-side efficiency [%] | 94.6 | [42] |
| AC-side efficiency [%] | 96.0 | [42] |
| Total inverter power [W] | = peak power PV system | |
| Lifetime [years] | 20 | |
| Availability [%] | 92–98 | Assumed downtime of 1–4 weeks per year. |
| Capacity density [$MW_p/km^2$] | 40–80 | [24,43] |
| Module degradation [%/year] | 0.5–1 | [18] |
| **Economic solar PV parameters** | | |
| Specific CAPEX for grid connection [US$(2021)/MW/km] | 847–3,769 | [44] |
| Specific CAPEX for road construction [$10^3$ US$(2021)/km] | 134.7–439.3 | [11,45,46] |
| Specific system CAPEX excl. grid and road [US$(2021)/$kW_p$] | 680–1,583 | [6,11,43,47–49] + [personal communication, SOE#1, SOE#2, Private sector #2, and Private sector #3] |
| OPEX [US$(2021)/$kW_p$/year] | 8–32 | |
| **Financial parameters for debt sizing and cash flow analysis** | | |
| Depreciation period [years] | 16 | [50] |
| Depreciation rate (straight-line) [%/year] | 6.25 | [50] |
| Salvage value [US$(2021)] | 0 | |
| Corporate tax rate [%] | 20 | [50] |
| Tariff [US¢(2021)/kWh] | 5.02–16.59 | See Supplementary Material E. |
| Inflation [%] | 1.5–5 | Period 2017–2022 [51] |
| Initial debt-to-capital ratio | 60–80% | [6,47,48,52] + [personal communication, SOE#1, SOE#2, Private sector #2, and Private sector #3] |
| Initial DSCR for debt sizing | 1.3 | [21] |
| Initial loan repayment period for debt sizing [years] | 20 | |
| After-tax cost of debt [%] | 5.0–10.0 | [48] + [personal communication, SOE#1, SOE#2, Private sector #2, and Private sector #3] |
| Cost of equity [%] | 12.0–13.8 | [48,52], excluding size premia |

enhanced conditions.

This paper aims to address the limitations of contemporary literature and to encourage more advanced analyses. Despite its application to PV in Indonesia, our framework is globally relevant and adaptable for other technologies and locations.

The paper is structured as follows. Section 2 describes the methods and materials for the site mapping, PV system modelling, and economic analysis. Section 3 presents and discusses the results. The paper ends with conclusions in Section 4.

## 2. Methods and materials

In the following sections, we describe (1) the geospatial analysis, (2) PV system modelling, and (3) the economic analysis as visualised in Fig. 1.

### 2.1. Mapping technically feasible sites for PV

We use *QGIS 3.18 Zürich* to map technically feasible PV sites starting with a base map of Indonesia's land area. Then, we add restriction layers to the base map and remove overlapping areas. The restriction layers and their buffers in Table 2 reflect technical (e.g. too steep terrain), environmental (e.g. peatlands), and social (e.g. proximity to settlements) constraints for PV implementation. We omit land use change, e.g. via urbanisation or reforestation, as the extrapolation of land use time series data, e.g. by Karra et al. [27], across PV's useful lifetime goes beyond this paper's scope. Nonetheless, land use change's impact on available land for PV should be addressed in future research.

After obtaining the technically feasible PV sites, we add the site-specific solar resource data to them. We use two complimentary datasets as explained further in section 2.2, namely ERA5 and *Global Solar Atlas (GSA)*. The ERA5 data is arranged in grid points 30 km apart from each other. We subdivide the PV sites with the rectangular grid spanned by the ERA5 data points. Then, we obtain the centroids of the subdivided sites and assign the closest ERA5 point to each of them. The centroids are also used to calculate the distances to the closest existing road [35] and grid connection point [36,37]. We assume substations and fossil-fuel-based generators ≥ 1 MW as eligible grid connection points. The GSA data is a raster file with pixels of roughly 1 $km^2$. Each pixel contains the local average PV power production in [$kWh/kW_p$/year] and is averaged inside the subdivided sites' area. Lastly, we remove sites smaller than 2.5 ha assuming a capacity density of 0.4 $MW_p$/ha [24], affecting 0.04% of all sites, to ensure a minimum PV plant size of 1 $MW_p$.

### 2.2. Solar PV system modelling and technical potential

We use the *PV_LIB Toolbox for MatLab* [38] to model the PV systems with the technical assumptions listed in Table 3. All used datasets and PV_LIB functions are listed in Supplementary Material D.

The PV system modelling is performed as follows. First, we calculate the plane-of-array irradiance considering a free-horizon scenario where the diffuse component is determined with the Isotropic Sky Diffuse Model. We assume an azimuth of 180° for sites on the Northern and 0° for sites on the Southern hemisphere [42], and calculate the tilt angle based on the sites' latitude [40]. Then, we use this incident irradiance to calculate the operating cell temperature, and further correct it for

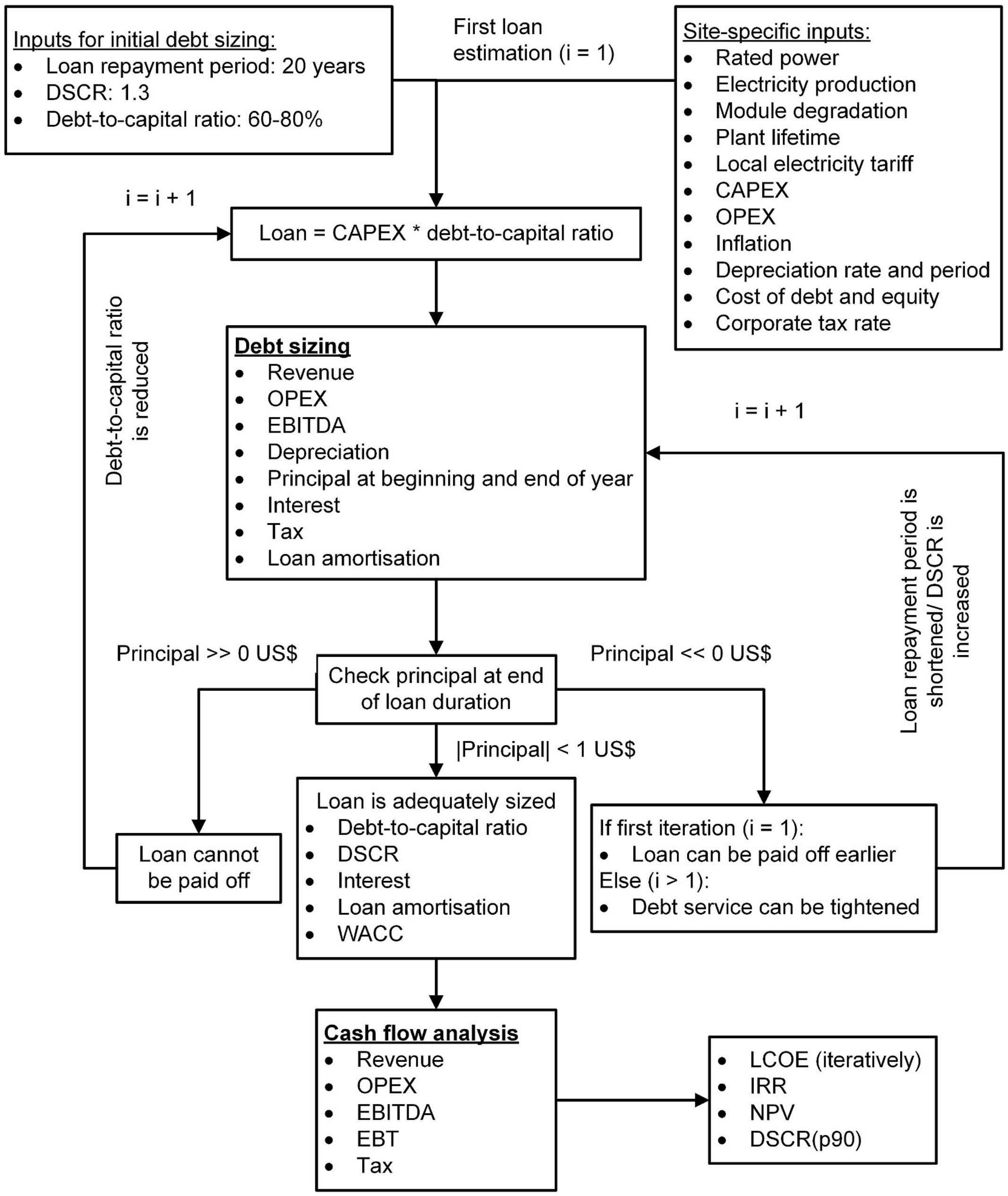


**Fig. 2.** Overview of the financial model, see Supplementary Materials G and H for equations.

soiling, spectral mismatch, and angle-of-incidence losses to generate the PV system's I–V performance. The maximum power point on the I–V characteristics represents the DC output of the PV system. The AC output is computed using GSA's assumptions for DC cable, inverter, transformer, and AC cable losses as well as availability factor, which amount to roughly 6% [42].

The steps above return a set of 20-year hourly AC power production profiles for each ERA5 point. Due to ERA5's coarse spatial resolution, these profiles do not yet reflect the detailed local topography, e.g. in mountainous areas. Therefore, we adjust, or *bias-correct* [53], the ERA5 power profiles with the finer GSA values in three steps. First, we calculate the averages of the ERA5 power profiles during the period covered by GSA. Second, we calculate site-specific bias-correction factors by comparing the GSA and ERA5 averages. Last, the factors are applied to each 1-h time step of the ERA5 power profiles. For example, if the average GSA value at one site is 5% higher than the corresponding average ERA5 value, each 1-h value of the 20-year ERA5 power profile is increased by 5%.

The technical PV potential comprises the aggregated annual bias-corrected AC power production at all technically feasible sites. In this study, we report the technical potential as average values for the socio-economic potential and as p90 values for the bankable potential based on the used inputs for their calculation, see respective sections.

### 2.3. *Economic analysis*

#### 2.3.1. *Socio-economic potential*

Following the papers reviewed in section 1.2, we report PV's socio-economic potential as LCOE, NPV, and IRR with Eqs. (1)–(4). The socio-economic potential is the part of the technical potential that is economically attractive from a public perspective [1,54], thus excluding private economic cost components like debt and tax expenses.

$$LCOE = \frac{CRF * CAPEX + OPEX}{AEP} \tag{1}$$

$$CRF = \frac{WACC * (1 + WACC)^T}{(1 + WACC)^T - 1} \tag{2}$$

$$NPV = \frac{-CAPEX + \sum_{t=1}^{T} \frac{(p*AEP - OPEX)}{(1+WACC)^t}}{P_{peak}} \tag{3}$$

$$0 = NPV = \frac{-CAPEX + \sum_{t=1}^{T} \frac{(p*AEP - OPEX)}{(1+IRR)^t}}{P_{peak}} \tag{4}$$

| Symbol | Meaning [unit] |
|---|---|
| AEP | Annual electricity production [kWh/year] |
| CAPEX | Capital expenses [US$] |
| CRF | Capital recovery factor [−] |
| IRR | Internal rate of return [%] |
| LCOE | Levelised cost of electricity [US¢/kWh] |
| NPV | Net present value [US$/kW$_p$] |
| OPEX | Operational expenses [US$/year] |
| p | Electricity tariff [US¢/kWh] |
| $P_{peak}$ | Installed peak power [kW$_p$] |
| T | Operational lifetime [years] |
| WACC | Weighted average cost of capital [%] |

For all plants, we assume $CAPEX = 963$ US\$(2021)/kW$_p$ and $OPEX = 23$ US\$(2021)/kW$_p$/year (inflation-adjusted average values from Ref. [47]), real *Weighted Average Cost of Capital (WACC)* = 9.5% [47] + (personal communication, SOE #1 and SOE #2, private sector #2 and private sector #3), and lifetime $T = 20$ years. For the annual electricity production *AEP*, we multiply the sites' areas with their respective GSA values and average capacity density of 60 MW$_p$/km$^2$ from Table 3.

The local electricity tariff $p$ is based on the Indonesian regulation at the time of the study (April 2022). The Ministry of Energy and Mineral Resources biannually publishes regional and national cost of power provision (*Biaya Pokok Penyediaan (BPP)* in Indonesian). If regional BPP > national BPP, PV producers receive up to 85% of the regional BPP, else the tariff is based on business-to-business negotiations [56]. We use the average tariffs since the regulation's introduction in 2017 for the socio-economic potential, and randomise the tariff within the minima and maxima (see Supplementary Material E) for the bankable potential. During the finalisation of the paper, a new tariff scheme was announced [57], to which we refer where relevant.

The socio-economic potential comprises the annual electricity production of all plants that fulfil LCOE $\leq$ tariff $p$, NPV $\geq$ 0 US$/kW$_p$, and IRR $\geq$ WACC.

### 2.3.2. Bankable potential

For the bankable potential, we use the financial model in Fig. 2, which consists of a debt sizing and cash flow analysis module. The financial model simulates the project finance steps in section 1.3 by sizing the debt provided by the lender and quantifying the plants' bankability.

The economic assumptions in Table 3 originate from academic and grey literature as well as expert elucidation. We contacted the eight experts listed in Supplementary Material F to source and validate the used input data and metrics. All monetary inputs are converted to US $(2021) using Supplementary Material C. Since we focus on PV's short- to medium term bankability, we use current cost assumptions and discuss our results against potential future costs. For the Monte Carlo simulation, we run the financial model 4,000 times per site and randomise the inputs assuming uniform distribution.

The debt sizing module iteratively determines the loan provided by the lender (see Supplementary Material G for equations). During the first iteration, the module uses default values for loan repayment period and sizing DSCR. Then, the module checks the remaining principal after 20 years. If the principal is positive, the loan cannot be paid off fully in time. Consequently, the debt-to-capital ratio is lowered until the loan can be fully paid off. If the principal is negative after 20 years, the loan could be paid off earlier. The module checks for the first year with a negative principal and sets that year as the new loan repayment period. Then, the loan is tuned via the sizing DSCR. For annual power production, we calculate the p90 value of the 20-year electricity production profile and apply it for each year.

**Table 4**
Impact of site exclusion groups in terms of land use and PV capacity. The percentage of total area relates to Indonesia's land area of 1,890,077 km$^2$. The potential is estimated with a capacity density of 40–80 MW$_p$/km$^2$.

| Exclusion Group | Excluded area [$10^3$ km$^2$] | Percentage of total area [%] | Excluded PV capacity [TW$_p$] |
|---|---|---|---|
| Geography | 170 | 9.0 | 6.8–13.6 |
| Water bodies/ wetlands | 519 | 27.4 | 20.8–58.6 |
| Built-up infrastructure | 85 | 4.5 | 3.4–6.8 |
| Agriculture | 577 | 30.4 | 23.1–46.2 |
| Forestry | 796 | 42.1 | 31.8–63.7 |
| Conservation | 226 | 12.0 | 9.0–18.1 |
| **Total** | **1,741** | **92.1** | **69.6–139.2** |

The cash flow analysis module calculates the metrics in Fig. 2 to determine PV's bankable potential (see Supplementary Material H for equations). These metrics comprise the LCOE [58], NPV [19], IRR [1], loan repayment period, and operational p90 DSCR. In line with practice [18], we report all metrics as p90 values to reflect the conservative, risk-averse stance of stakeholders like lenders. The LCOE is computed iteratively given the circular relationship between revenue and tax. We use the cost of equity as discount rate and consider it the sponsors' minimum required IRR. All running expenses are tax-deductible except for principal payments. For annual power production, we use the site-specific, bias-corrected AC power production profiles from section 2.2. After calculating the metrics, the bankable potential is the part of the technical potential that fulfils the following conditions:

- LCOE below 85% of local BPP
- NPV $\geq$ 0 US$/kW$_p$ [16]
- Operational p90 DSCR $\geq$ 1.3 [17]
- IRR $\geq$ minimum IRR + risk premium 0–10% [17]
- Loan repayment period $\leq$ 8–18 years [17]

The financial model has several limitations. First, we assume overnight construction and omit interest payments during construction, which we deem acceptable considering PV's construction period of 6–12 months [17]. Second, we omit more advanced project finance elements, like debt service reserve accounts. Third, Monte Carlo simulation does not track the studied input combinations, and assesses some input combinations several times and others not at all. Systematic sampling methods like Latin Hypercube Sampling would avoid this issue, but would become computationally expensive with the broad set of inputs randomised in this study. Thus, we opted for Monte Carlo simulation and chose 4,000 iterations as a compromise between runtime and thoroughness of explored combinations. Fourth, the techno-economic assumptions in Table 3 are applied nationwide due to lack of subnational data despite the potentially significant differences between Indonesian islands.

We justify these limitations with the purpose of our framework to obtain ballpark estimations of PV's bankable potential across a large geographic scale. There can be thousands of sites to be analysed, which necessitates a lean financial model to limit computational cost and runtime. Considering this, our framework offers a scouting tool for interesting sites, but cannot replace more detailed, project-specific assessments.

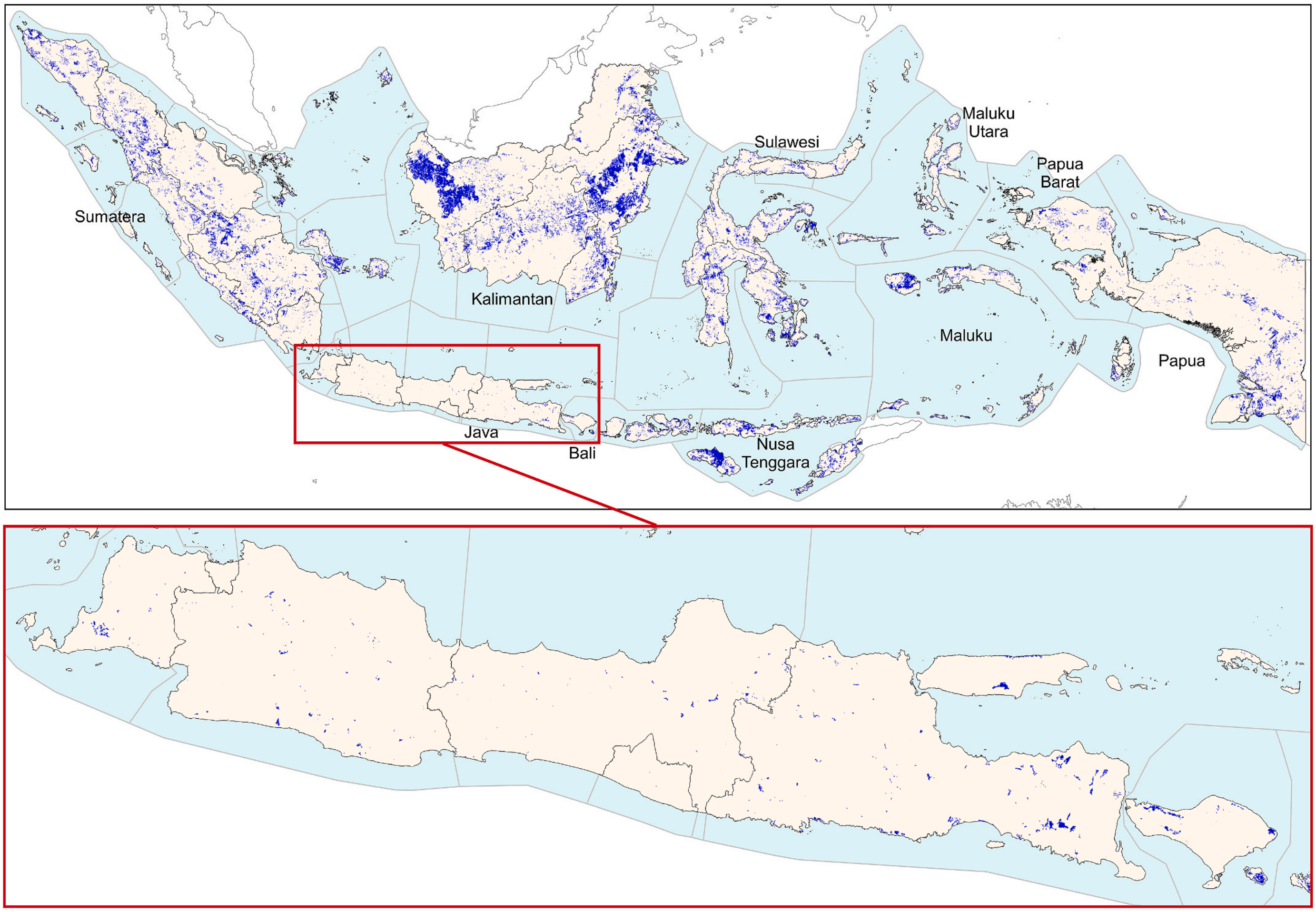


**Fig. 3.** Suitable sites for utility-scale PV (dark blue) on Indonesia's land area. The bottom image zooms in on Java and Bali. The white areas are neighbouring countries; the light blue areas are marine provincial borders. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

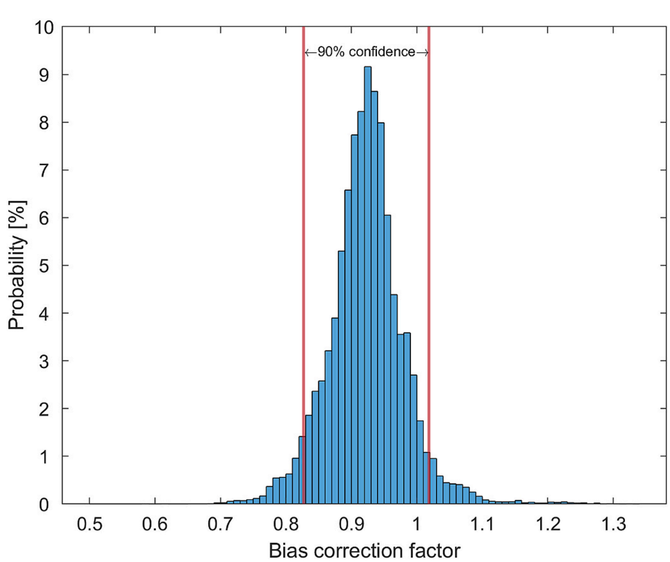


**Fig. 4.** Distribution of bias correction factors across PV sites in Indonesia and their 90% confidence range.

### 2.4. Sensitivity analysis

We perform a sensitivity analysis to show the most impactful inputs and most sensitive outputs. First, we calculate a reference value for each metric using the average values from Table 3. Then, we vary each input by ±20% and compare the change of output to the reference. Moreover, we study the impact of (1) CAPEX reduction, (2) running expense reduction, and (3) revenue increase and discuss how these could be materialised with policies. We again use the average values from Table 3 except for the inputs relevant to the three groups, which are then varied along a range to assess their impact on the metrics.

After the policy analysis, we re-run the Monte Carlo simulation using the most effective policies. With this, we want to showcase the usefulness of our framework for more enhanced policy recommendations compared to contemporary literature.

## 3. Results and discussion

### 3.1. Suitable PV sites and their technical potential

Table 4 shows how much land and PV capacity are removed per site exclusion group. Under current land use, 92.1% of Indonesia's land is

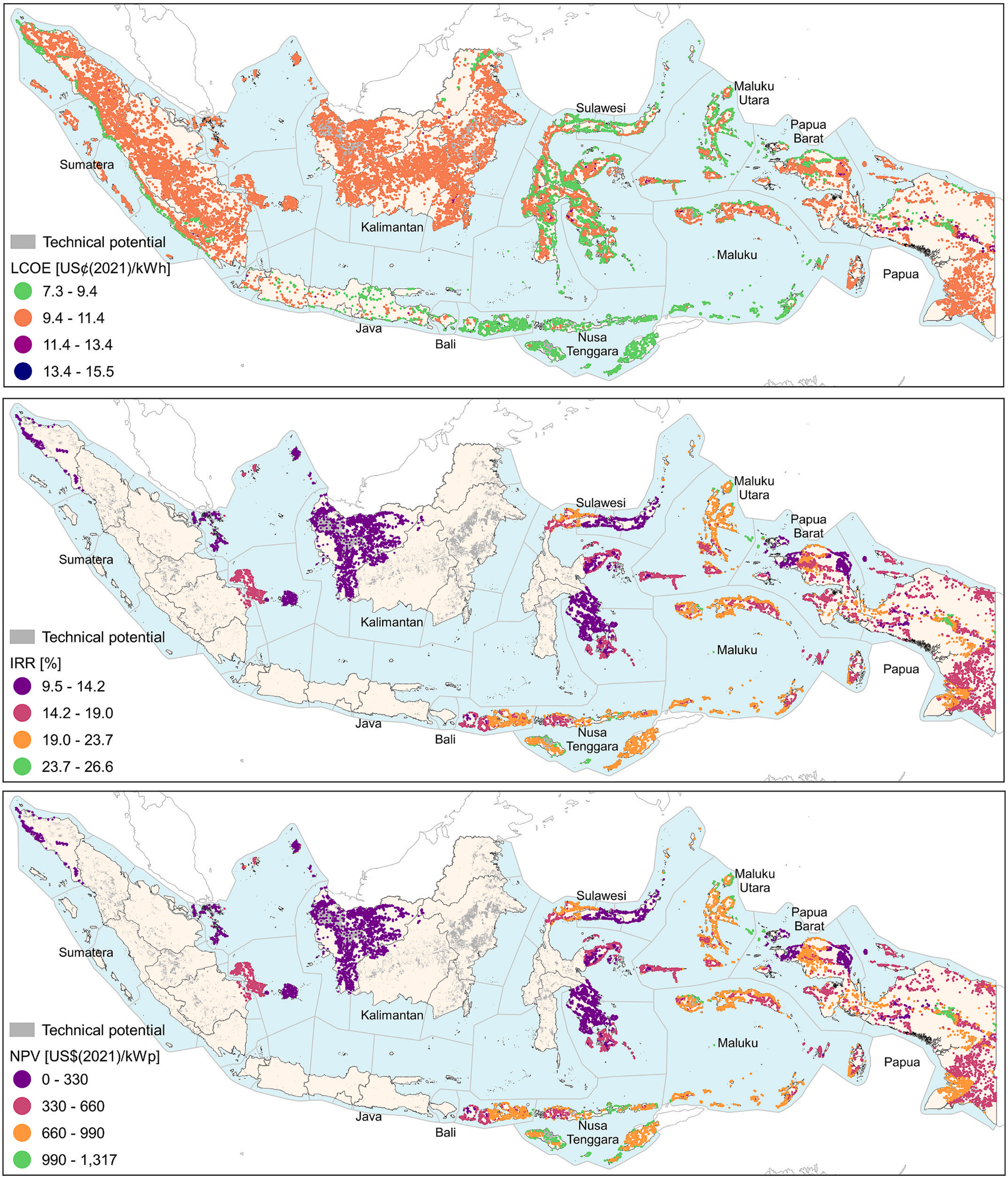


**Fig. 5.** LCOE, IRR, and NPV of utility-scale PV in Indonesia forming the socio-economic potential. For better visibility, only sites with NPV ≥ 0 US$/kW$_p$ and IRR ≥ WACC 9.5% are shown as magnified points.

unavailable for utility-scale PV. Forests, agricultural land, and wetlands are the most impactful, especially on Java where only 0.6% of land remains. Most available land is found on Kalimantan, Sulawesi, and Sumatera, with 12.5%, 9.0%, and 6.8% of total land area, respectively.

Across the sites in Fig. 3, the p90 capacity factor ranges between 8.9 and 18.5%. Moreover, our PV system model tends to overestimate power production with bias correction factors between 0.83 and 1.02 on the 90% confidence interval (see Fig. 4). Both aspects can be explained by GSA's high spatial resolution, which captures the local topography, e.g. in mountainous regions, better than the ERA5 data does. The p90 technical potential amounts to 6.6 $TW_p$ and 8,077 TWh/year, which differs from other estimates like 3.4–20 $TW_p$ [24] and 1.3 $TW_p$ [4], most likely due to differences in used input data and methods, e.g. for site selection and PV system modelling.

The technical potential exceeds 2030 electricity demand [55] by a manifold on all islands except for Java and Bali, where the p90 technical potential of 48.6 TWh/year covers 16.6% of demand (see summary table at the end of section 3).

These findings show the opportunities and challenges of utility-scale, land-based PV. The technical potential could cover large shares of future demand, but only where open land is readily available. On islands like Java, the potential is limited by agriculture, forestry, and cities. Suitable alternatives for these regions could be rooftop and agro-PV for urban and agricultural land, inter-island power connections to islands with excess PV resources, or offshore energies.

### 3.2. Socio-economic and bankable potential

#### 3.2.1. Socio-economic potential

Fig. 5 shows PV's LCOE, NPV, and IRR across Indonesia. Our LCOE range of 7.3–15.5 US¢(2021)/kWh is wider than IESR's [47] currency-converted range of 6.0–10.7 US¢(2021)/kWh, most likely due to the GSA's finer representation of solar resources. The average technical and socio-economic potential amount to 12.2 and 5.9 PWh/year, respectively. As displayed in Table 5, the socio-economic potential is mainly located in East Indonesia and on Kalimantan and absent on Java & Bali due to differences in tariffs and land availability. As the latter islands are Indonesia's economic centres, the socio-economic potential could only cover 152.7 TWh/year, or 34.3%, of 2030 demand.

These results are already useful to indicate economically attractive locations for PV. However, they do not yet consider location-specific grid connection and road construction cost as well as the PV plants' bankability.

**Table 5**
Technical and socio-economic potential per island group.

| Island (group) | Technical potential [TWh/year] | 2030 demand [55] [TWh] | Socio-economic potential [TWh/year] | | Share of 2030 demand [%] |
|---|---|---|---|---|---|
| | | | Not capped by demand | Capped by demand | |
| Java & Bali | 73.5 | 292.3 | 0 | 0 | 0 |
| Sumatera | 2,602 | 84.9 | 419 | 84.9 | 100 |
| Kalimantan | 5,298 | 27.0 | 1,932 | 27.0 | 100 |
| Sulawesi | 1,418 | 24.8 | 767 | 24.8 | 100 |
| Nusa Tenggara, Maluku & Papua (East Indonesia) | 2,826 | 16.0 | 2,823 | 16.0 | 100 |
| **Indonesia** | **12,216** | **445.0** | **5,941** | **152.7** | **34.3** |

#### 3.2.2. Bankable potential

Figs. 6 and 7 display the impact of the metric-specific thresholds on PV's p90 bankable potentials. We show that tariffs and the risk perception of project stakeholders are two key influences on PV's bankable potential. Regarding the former, the LCOE ≤ minimum tariff requirement only leaves 26.2 TWh/year bankable. This highlights the inadequacy of tariffs and the detrimental effects of the recent tariff reductions as most minimum tariffs pertain to the last BPP update [59]. Regarding the latter, the bankable potential drops to zero if sponsors apply a risk premium of 2.5% to the cost of debt of 12.5% observed for Indonesian PV projects in 2021 [52]. The loan repayment periods of these projects was 15–16 years [52], which seems conducive for PV's bankability. However, there are domestic lenders with more restrictive loan repayment periods below 10 years, amongst others due to their limited experience in financing PV projects [60]. These observations show that a safe investment environment for PV is key to gain investors' confidence, e.g. via stable, adequate tariffs and capacity building in the domestic banking sector.

In the following, we discuss the p90 bankable potential using LCOE ≤ minimum tariff, IRR ≥ 12.5% and loan repayment period ≤ 15 years [52].

Fig. 8 shows the p90 bankable potential of 26.2 TWh/year mapped across Indonesia. The bankable PV sites are situated in East Indonesia, namely in Papua and Maluku Utara, due to high and stable recent tariffs and ample available land and solar resources. These findings harmonise with current statistics and Indonesia's energy strategy from 2014 [61]. Today, more than half of Indonesia's solar capacity is installed in East Indonesia [62], e.g. as solar lamps [63] and Diesel generator replacements [64]. The BPP tariff scheme encourages these developments as rural BPP tend to be higher than urban BPP. However, East Indonesia's 2030 demand of 16 TWh only takes up 3.6% of national demand. Hence, PV would contribute little to meeting Indonesia's carbon neutrality targets [55] and even less considering that the bankable potential is not spread over entire East Indonesia, but only parts of it.

Next, we compare our results with the outcome of recent Indonesian PV auctions. For the 60 $MW_p$ Saguling floating PV plant in West Java, the awarded bid price (3.7 US¢/kWh [64]) is lower than the local BPP. Other recent bids further support that PV's bankable potential could be higher and more distributed than reported so far. Using the best-case values in Table 3, we obtain an LCOE of 6.2 US¢(2021)/kWh for the site closest to Saguling, based on total specific CAPEX = 785 US $(2021)/kW_p$ and WACC = 6.8%, amongst others. According to one expert (personal communication, private sector #1), many developers bidding such prices originate from Middle Eastern countries with access to cost of capital of 5.8% and lower. This and further CAPEX reduction

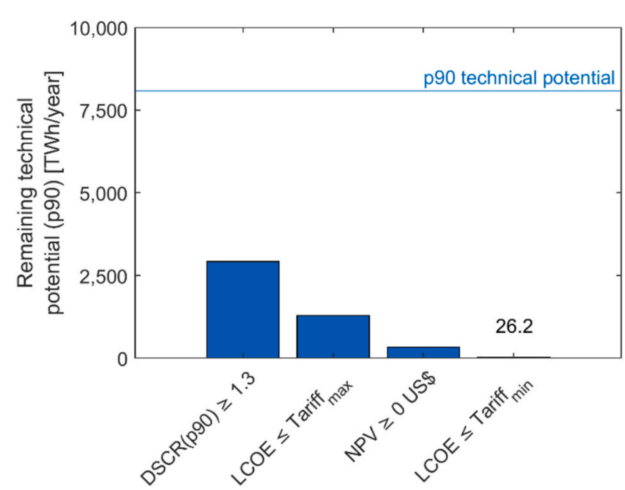


**Fig. 6.** Impact of DSCR, tariff, and NPV thresholds as criteria for PV's p90 bankable potential.

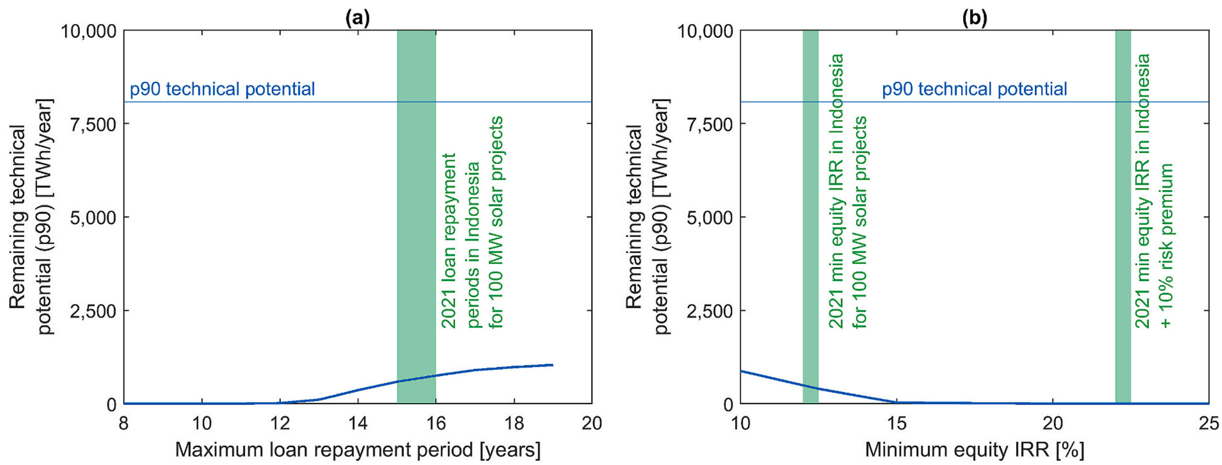


**Fig. 7.** Impact of maximum loan repayment period and minimum equity IRR on PV's p90 bankable potential. The green patches show thresholds found in practice for Indonesia [52] as well as general practice from literature [17]. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

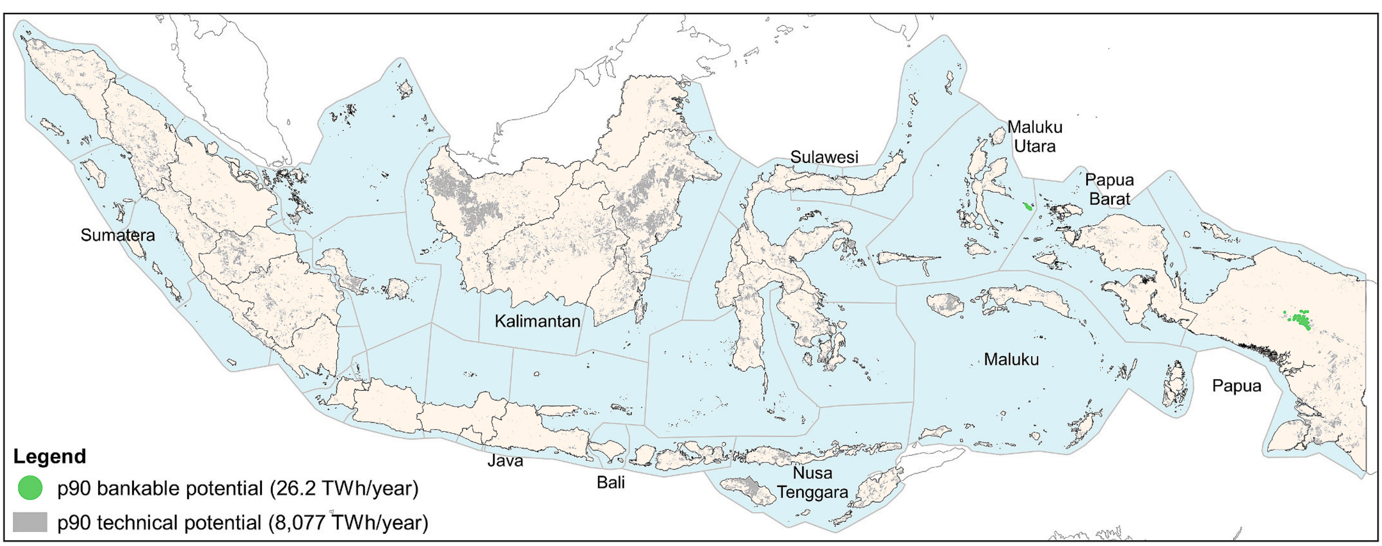


**Fig. 8.** Map of bankable p90 bankable potential across Indonesia using LCOE ≤ minimum tariff, IRR ≥ 12.5% and loan repayment period ≤ 15 years as thresholds. The sites with bankable potential are displayed as magnified green points for clarity. The p90 bankable potential in this illustration does not account for 2030 electricity demand. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

**Table 6**
p90 technical and economic characteristics of two utility-scale PV plants, one with the best overall economic performance and another one representative for Java and Bali.

| | Most bankable site | Site representative for Java and Bali |
|---|---|---|
| Location | Papua<br>138.9°E, 4.0°S | East Java<br>113.3°E, 7.8°S |
| Total area [$km^2$] | 0.665 | 0.826 |
| Distance to road [km] | 0.444 | 0.159 |
| Distance to grid [km] | 9.75 | 5.42 |
| Tariff range [US¢(2021)/kWh] | 16.59–18.31 | 5.40–6.25 |
| Size of PV plant [$MW_p$] | 29.2 | 36.5 |
| Mean capacity factor [%] | 16.5 | 16.8 |
| CAPEX [$10^3$ US$(2021)] | 65,470 | 81,258 |
| Specific CAPEX [US$(2021)/$kW_p$] | 1,530 | 1,504 |
| LCOE [US¢/kWh] | 14.2 | 14.0 |
| IRR [%] | 19.3 | −11.4 |
| NPV [US$/$kW_p$] | 229 | −941 |
| Debt-to-capital ratio [%] | 62.0 | 26.3 |
| Loan repayment period [years] | 11 | 20 |
| Operational DSCR [−] | 1.47 | 1.28 |
| WACC [%] | 10.5 | 11.9 |

potentials, e.g. from economies of scale mostly omitted in this study, could explain why recent bid prices were so low.

Table 6 reports the p90 technical and economic results of the most bankable site (i.e. highest NPV) and a site in Java representing PV's current barriers in urbanised, high-demand Indonesia. Despite similar CAPEX and capacity factors, the site in East Java has a significantly lower debt-to-capital ratio of 26.3% and longer loan repayment period of 20 years, mainly due to the low tariffs and expected revenue there. Moreover, the Java site might fail debt service obligations with an operational p90 DSCR below 1.3. In contrast, the high and steady tariffs in Papua enable a p90 loan repayment period of 10 years, p90 debt-to-capital ratio of 62.0%, and an operational p90 DSCR of well above 1.3, thus indicating a low risk of loan default under the used techno-economic assumptions.

### 3.3. *Sensitivity analysis and impact of policies*

Fig. 9 illustrates the results of the sensitivity analysis. The NPV is the most sensitive metric, followed by loan repayment period, IRR, and LCOE as the least sensitive metric. The most influential parameters are tariffs (except for LCOE), availability factor, system CAPEX, and debt-to-capital ratio. There are also several asymmetries due to physical limitations (e.g. availability factor cannot exceed 100%) and inherent asymmetry (e.g. a change of denominator by +/− 20% entails changes by (1–1/1.2) = −16.6% and (1–1/0.8) = +25.0%).

These findings underline the importance of adequate and consistent tariffs, but also the necessity for cost reductions. Compared to other countries, PV's costs in 2021 were high in Indonesia [65] and we discuss options for CAPEX reduction later in this section. Maximising the plants' runtime is equally important as highlighted by the impact of availability factor. Previous PV projects failed in Indonesia as developers abandoned the plants after installation and local communities lacked expertise to operate and maintain them (personal communication, private sector #4). One solution could be to establish a network of service and maintenance hubs across Indonesia's islands, e.g. orchestrated by the state utility company PLN.

Fig. 10 shows that policies (1) reducing CAPEX and (2) increasing revenue are most effective to boost the bankability of the Papua and East Java sites from section 3.2.2.

The (1) CAPEX reduction could be achieved with a temporary lift of domestic goods and services obligations (called *Local Content Rule (LCR)*). Most consulted experts perceive the LCR as a major barrier since Indonesia's manufacturing capacity cannot yet meet official implementation targets (personal communication, private sector #1, #2 & #3; SOE #1 and #2). On average, the experts estimate 80% lower costs for imported modules (personal communication, private sector #3, SOE #1 and #2), which entails 25% lower system CAPEX using IRENA's cost breakdown [6]. These cost reductions could be achieved without direct public funding, and generate income via import duties. LCR could stepwise be re-established while Indonesia's PV industry is developed with the help of international collaboration.

The (2) revenue increase could be achieved via a carbon tax added to the current BPP-based tariffs. A carbon tax of 50 US$/$tCO_2$eq would increase tariffs by 5.1 US¢(2021)/kWh [66] and moves the East Java plant closer to bankability. This tax rate is higher than Indonesia's current tax of 2.1 US$(2021)/$tCO_2$e [67], but comparable to 2020 carbon tax rates and emission allowances in Europe [68]. The East Java plant would receive between 10.50 and 11.35 US¢(2021)/kWh, which is not far off from the up to 11.47 US¢(2022)/kWh that PV systems could receive in Java with the upcoming tariff scheme [57]. Therefore, the new tariff scheme could be a crucial step towards Indonesia's successful energy transition.

In contrast, the reduction of running expenses, namely OPEX, cost of debt, and corporate tax, only limitedly improves bankability, which harmonises with recent practical findings [69]. Therefore, policies addressing running expenses could be more suitable at later stages of Indonesia's energy transition.

Then again, the policies regarding CAPEX reduction and revenue increase could also have drawbacks. Importing PV panels from abroad might create fear of losing domestic jobs, while the costs of the carbon tax could be passed on to electricity consumers. Both drawbacks could fuel social resistance against widespread PV implementation, so future research must address how such policies could be introduced in practice.

Fig. 11 and Table 7 presents PV's bankable potential with a fixed, national feed-in tariff of 11.5 US¢(2021)/kWh and temporary LCR lift for solar modules (i.e. 25% system CAPEX reduction). With these two measures, the p90 bankable potential amounts to 348.6 TWh/year if not restricted by 2030 demand. If restricted by demand, the p90 bankable potential is 23.0 TWh/year with bankable sites now also being located on Java, Bali, and Sulawesi. Solar irradiation becomes a key determinant for bankability with required p90 capacity factors of at least 15.9%. On islands like Kalimantan and Sumatera, p90 capacity factors only reach up to 15.4%, which is why none of the p90 technical potential is bankable there.

If the policy-enhanced p90 bankable potential would be materialised, PV's contribution to the 2030 electricity mix would be 100% in Papua as well as East and West Nusa Tenggara, 1.2% on Java and Bali, 13.7% in Sulawesi, and 5.2% nationally. Therefore, feed-in tariffs and LCR lifts alone might not suffice to boost PV's widespread bankability. Then again, system CAPEX are projected to decrease by roughly 50% until 2050 [49]. As supported by Fig. 10, the bankable potential might increase significantly if these projections hold true.

We finish this section with a brief discussion on PV's integration into Indonesia's energy system. Currently, most of Indonesia's electricity is produced using fossil fuels [70]. These generators are dispatchable on-demand, whereas PV's production is non-dispatchable and depends on the weather and time of day. The shift from dispatchable to non-dispatchable generation requires a transformation of the power system. The extent of the transformation depends on the grid's constitution and properties [71] and would be more extensive on Papua than on Java and Bali given the limited transmission grid infrastructure of the former [55]. Nonetheless, options for maintaining grid stability are ample and include grid reinforcement and extension, demand response technologies like smart electric vehicle charging, stationary batteries, and power-to-X [72]. Moreover, weather forecasting systems could help predicting PV's production and taking adequate balancing measures [73].

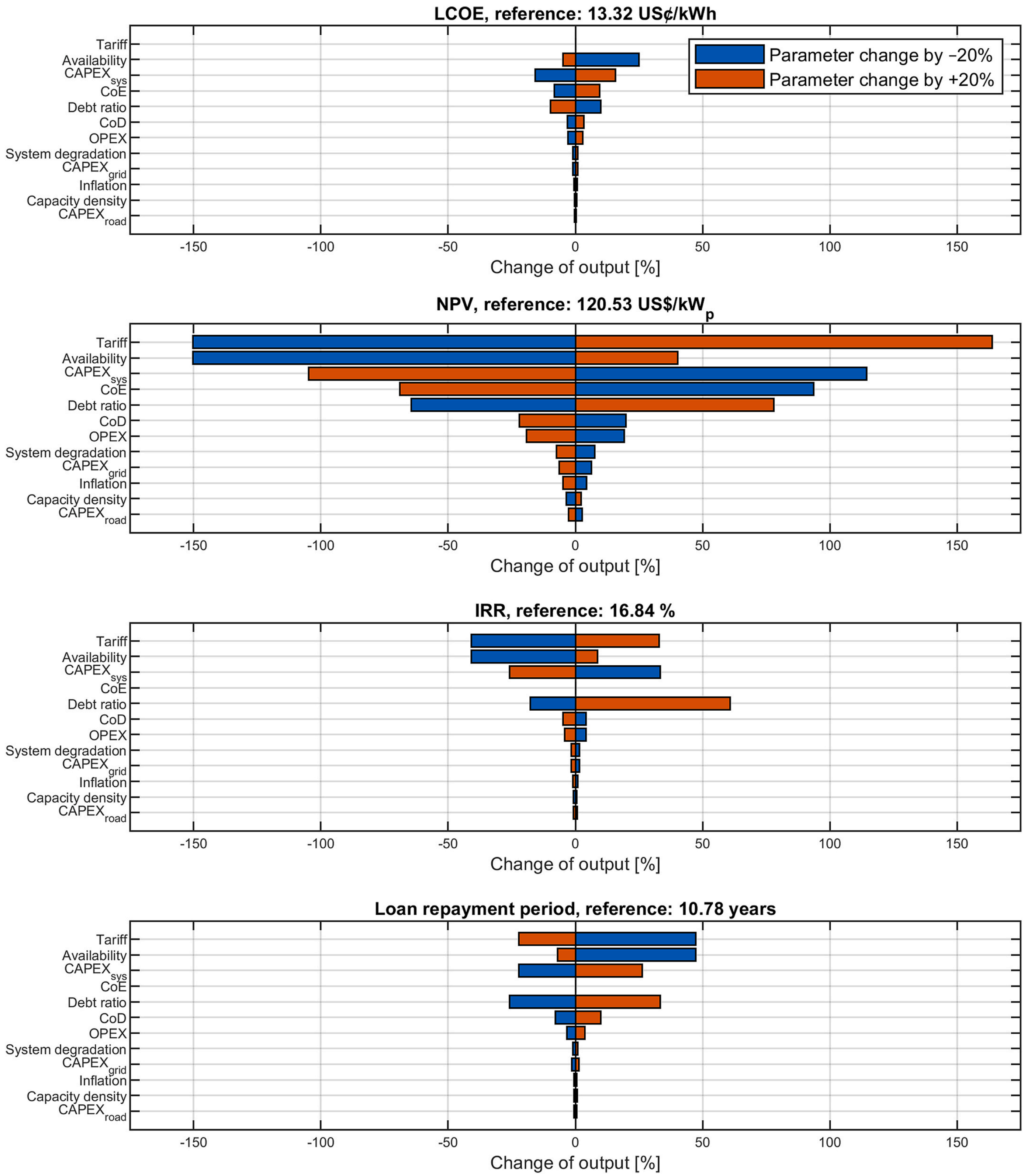


**Fig. 9.** Sensitivity analysis for utility-scale PV sites with positive median NPV (6,390 out of 38,143 sites). All inputs are varied by +/− 20% except for the availability factor, which cannot exceed 100%.

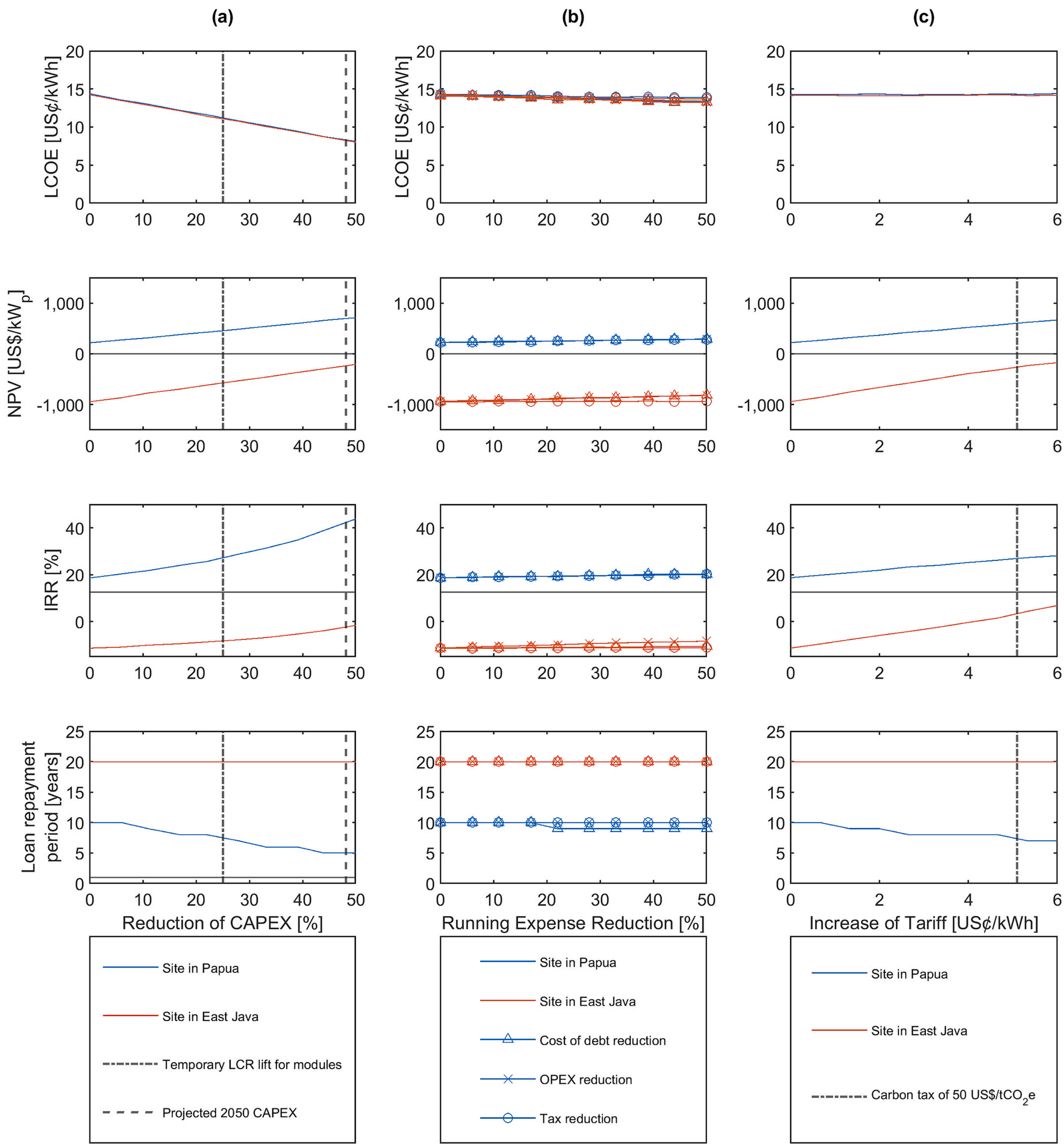


**Fig. 10.** Impact of (a) CAPEX reduction, (b) reduction of running expenses, and (c) increase of revenue on p90 metrics pertaining to the two reference sites analysed in section 3.2.2. LCR: for local content rule. Projected 2050 CAPEX in Indonesia are taken from the technology catalogue by the National Energy Council [49].

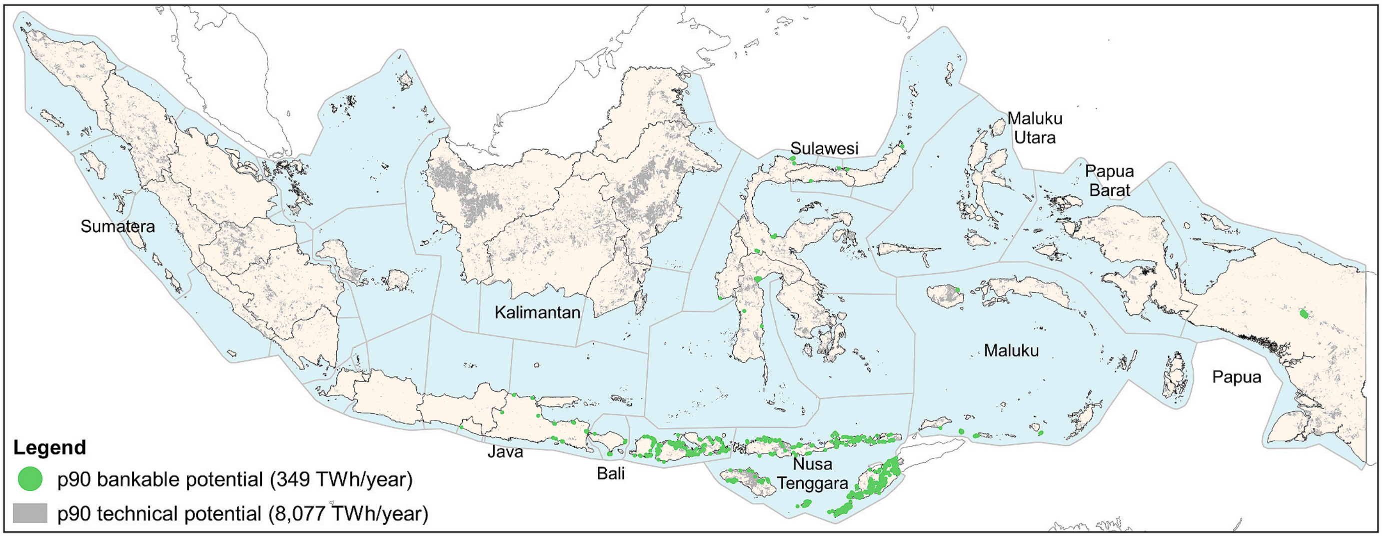


**Fig. 11.** Map of bankable p90 bankable potential across Indonesia with a national feed-in tariff of 11.5 US¢(2021)/kWh and temporary lift of local content for solar modules. Thresholds for bankability are LCOE ≤ feed-in tariff, IRR ≥ 12.5% and loan repayment period ≤ 15 years. The sites with bankable potential are displayed as magnified green points for clarity. The p90 bankable potential in this illustration does not account for 2030 electricity demand. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

**Table 7**
p90 technical and bankable PV potential per island (group) in Indonesia based on current conditions and an alternative scenario with a feed-in tariff of 11.5 US¢ (2021)/kWh and temporary lift of local content for solar modules.

| Island (group) | p90 technical potential [TWh/year] | 2030 demand [55] [TWh] | Current conditions: p90 bankable potential [TWh/year] – Not capped by demand | Current conditions: p90 bankable potential [TWh/year] – Capped by demand | Current conditions: Share of 2030 demand [%] | FIT + Temporary LCR lift: p90 bankable potential [TWh/year] – Not capped by demand | FIT + Temporary LCR lift: p90 bankable potential [TWh/year] – Capped by demand | FIT + Temporary LCR lift: Share of 2030 demand [%] |
|---|---|---|---|---|---|---|---|---|
| Java & Bali | 48.6 | 292.3 | 0 | 0 | 0 | 3.6 | 3.6 | 1.2 |
| Sumatera | 1,718 | 84.9 | 0 | 0 | 0 | 0 | 0 | 0 |
| Kalimantan | 3,503 | 27.0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulawesi | 940 | 24.8 | 0 | 0 | 0 | 3.4 | 3.4 | 13.7 |
| Nusa Tenggara, Maluku & Papua (East Indonesia) | 1,868 | 16.0 | 26.2 | 16.0 | 100 | 341.6 | 16.0 | 100 |
| **Indonesia** | **8,077** | **445.0** | **26.2** | **16.0** | **3.6** | **348.6** | **23.0** | **5.2** |

Since we did not consider the costs of the technologies above, follow-up research could address PV's bankability from an energy system perspective, e.g. via energy system optimisation modelling.

## 4. Conclusions

This paper presents a framework that incorporates project finance into geospatial analyses to calculate and map the bankable potential of renewables. The framework is applied for utility-scale, land-based PV in Indonesia, but can easily be adapted for other technologies, locations, and institutional contexts. We map suitable sites, simulate 20 years of hourly power production, and calculate the bankable potential with debt sizing and cash flow models and Monte Carlo simulation. We express the socio-economic potential as average values and the bankable potential as p90 values, which reflects the worst 10% of the sample generated by the Monte Carlo simulation.

The paper is motivated by the limitations of current PV literature, namely (1) lack of studies on bankable potentials, (2) unclear economic potential reporting, (3) lack of transparent reporting of inputs and limited set of outputs, (4) lack of uncertainty and sensitivity analysis, and (5) potentially limited future relevance. We contribute to the academic body by proposing a framework that reports present and policy-enhanced bankable potentials across a large geographic scale based on systematically selected metrics and inputs collected from literature and validated by experts.

The average technical and socio-economic PV potentials are 12,216 TWh/year and 5,941 TWh/year, respectively. The socio-economic potential could serve 152.7 TWh, or 34.3%, of national 2030 demand (disregarding the mismatch between bankable supply and demand of individual islands within provinces). These potentials are significantly higher than the values pertaining to the bankable potential where we consider the risks of financing PV projects. We report a p90 technical potential of 8,077 TWh/year, out of which 26.2 TWh/year are bankable under current conditions. With the latter, PV could cover 16.0 TWh, or 3.6%, of national 2030 demand.

For both the socio-economic and bankable potential, the economically most attractive locations are situated in East Indonesia where tariffs are high and consistent and solar resources and available land ample. On Java and Bali, the technical potential is limited and the economic potential is currently zero due to limited available land for PV and low tariffs.

The bankable potential is not only strongly affected by tariffs, but also by the thresholds set by project stakeholders via risk premia and loan repayment period. Policies reducing CAPEX and increasing revenues are the most effective to boost bankability. With a national feed-in tariff of 11.5 US¢(2021)/kWh and CAPEX reduction by 25% via a temporary lift of local content obligations, the p90 bankable potential would increase to 348.6 TWh/year. However, PV would still not be bankable in Kalimantan and Sumatera, and the contribution to 2030 national demand would only be 23.0 TWh/year, or 5.2%. Therefore, further measures might be necessary to enable PV's widespread bankability, e.g. via a temporarily higher feed-in tariff above 11.5 US¢ (2021)/kWh. Then again, the bankable potential might increase significantly if projected cost reductions until 2050 materialise.

Based on our analysis, we recommend the following four policies. First, a national feed-in tariff as recently announced via presidential decree would establish long-term security in terms of expected revenue. Second, a temporary lift of local content for PV-related goods might entail low investment costs and a steady supply of PV modules in line with implementation targets. Third, the domestic manufacturing capacity could be developed with the aid of foreign expertise. Fourth, capacity building in Indonesia's banking sector could increase access and decrease costs of domestic debt and thus reduce the dependency on foreign lenders.

Future research could address the limitations of our framework, like (1) omission of land use change over time, (2) simplified debt sizing and cash flow analysis, (3) omission of future cost reductions, (4) exclusion of complex macroeconomic policies, and (5) omission of grid stabilising technologies.

## Author contributions

JL: Conceptualisation; Data curation; Formal analysis; Investigation; Methods & Materials; Writing: original draft, ZK: Validation; Writing – review & editing, YZ: Contributions to methodology; Validation; Writing – review & editing, OI: Contributions to methodology; Validation; Writing – review & editing, ZA: Conceptualisation; Methods & Materials; Validation; Writing – review & editing, JQ: Supervision; Writing – review & editing, AP: Writing – review & editing, KB: Contributions to methodology; Supervision; Validation; Writing – review & editing.

## 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.

## Data availability

Data and code is openly available following the links in the data availability section

## Acknowledgements

The work reported in this paper is funded by a grant from the Dutch research council NWO for the project entitled "Regional Development Planning and Ideal Lifestyle of Future Indonesia", under the NWO Merian Fund call on collaboration with Indonesia. Many thanks to Femke Pragt, MSc, whose master thesis inspired this paper. Map data copyrighted OpenStreetMap contributors and available from https://www.openstreetmap.org.

## Supplementary materials

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2023.128555.

## References

[1] Blok K, Nieuwlaar E. Introduction to energy analysis. third ed. Abingdon: Taylor and Francis; 2021.
[2] Lopez A, Roberts B, Heimiller D, Blair N, Porro GUS. Renewable energy technical potentials: a GIS-based analysis. 2012. Denver.
[3] Hoogwijk M, de Vries B, Turkenburg W. Assessment of the global and regional geographical, technical and economic potential of onshore wind energy. Energy Econ 2004;26:889–919. https://doi.org/10.1016/j.eneco.2004.04.016.
[4] Royal Dutch Shell. Global energy resources database. 2020. https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/shell-scenarios-energy-models/energy-resource-database.html#iframe=L3dlYmFwcHMvRW5lcmd5UmVzb3VyY2VEYXRhYmFzZS8. [Accessed 2 December 2020].
[5] Global EMBER. Electricity review: global trends. 2023. London.
[6] International Renewable Energy Agency. Renewable power generation costs in 2020. 2020. Abu Dhabi.
[7] Jain A, Das P, Yamujala S, Bhakar R, Mathur J. Resource potential and variability assessment of solar and wind energy in India. Energy 2020;211:118993. https://doi.org/10.1016/j.energy.2020.118993.
[8] Ouchani FZ, Jbaihi O, Alami Merrouni A, Maaroufi M, Ghennioui A. Yield analysis and economic assessment for GIS-mapping of large scale solar PV potential and integration in Morocco. Sustain Energy Technol Assessments 2021;47:101540. https://doi.org/10.1016/j.seta.2021.101540.
[9] Peña Sánchez EU, Ryberg SD, Heinrichs HU, Stolten D, Robinius M. The potential of variable renewable energy sources in Mexico: a temporally evaluated and geospatially constrained techno-economical assessment. Energies 2021;14. https://doi.org/10.3390/en14185779.
[10] Sun YW, Hof A, Wang R, Liu J, Lin YJ, Yang DW. GIS-based approach for potential analysis of solar PV generation at the regional scale: a case study of Fujian Province. Energy Pol 2013;58:248–59. https://doi.org/10.1016/j.enpol.2013.03.002.
[11] Sunarso A, Ibrahim-Bathis K, Murti SA, Budiarto I, Ruiz HS. GIS-based assessment of the technical and economic feasibility of utility-scale solar PV plants: case study in West kalimantan province. Sustainability 2020;12:1–12. https://doi.org/10.3390/SU12156283.
[12] Zhang Y, Ren J, Pu Y, Wang P. Solar energy potential assessment: a framework to integrate geographic, technological, and economic indices for a potential analysis. Renew Energy 2020;149:577–86. https://doi.org/10.1016/j.renene.2019.12.071.
[13] Al-Ghussain L, Ahmad AD, Abubaker AM, Abujubbeh M, Almalaq A, Mohamed MA. A demand-supply matching-based approach for mapping renewable resources towards 100% renewable grids in 2050. IEEE Access 2021;9:58634–51. https://doi.org/10.1109/ACCESS.2021.3072969.
[14] Ramírez-Sagner G, Mata-Torres C, Pino A, Escobar RA. Economic feasibility of residential and commercial PV technology: the Chilean case. Renew Energy 2017;111:332–43. https://doi.org/10.1016/j.renene.2017.04.011.
[15] Steffen B. The importance of project finance for renewable energy projects. Energy Econ 2018;69:280–94. https://doi.org/10.1016/j.eneco.2017.11.006.
[16] Un ESCWA. Guidebook for project developers for preparing renewable energy investments business plans. 2017. Beirut.
[17] IFC. Utility-scale solar photovoltaic power plants, vols. 35–9; 2015.
[18] Raikar S, Adamson S. Renewable energy finance. First. London: Academic Press; 2019.
[19] Jadidi H, Firouzi A, Rastegar MA, Zandi M. Bayesian updating of solar resource data for risk mitigation in project finance. Sol Energy 2020;207:1390–403. https://doi.org/10.1016/j.solener.2020.07.096.
[20] Firouzi A, Meshkani A. Risk-based optimization of the debt service schedule in renewable energy project finance. Util Pol 2021;70:101197. https://doi.org/10.1016/j.jup.2021.101197.
[21] Pacudan R. Implications of applying solar industry best practice resource estimation on project financing. Energy Pol 2016;95:489–97. https://doi.org/10.1016/j.enpol.2016.02.021.
[22] Heck N, Smith C, Hittinger E. A Monte Carlo approach to integrating uncertainty into the levelized cost of electricity. Electr J 2016;29:21–30. https://doi.org/10.1016/j.tej.2016.04.001.
[23] Gu Y, Zhang X, Are Myhren J, Han M, Chen X, Yuan Y. Techno-economic analysis of a solar photovoltaic/thermal (PV/T) concentrator for building application in Sweden using Monte Carlo method. Energy Convers Manag 2018;165:8–24. https://doi.org/10.1016/j.enconman.2018.03.043.
[24] Beyond IESR. Gigawatts : unleashing Indonesia ' s solar potential. 2021. 207.
[25] Burke PJ, Widnyana J, Anjum Z, Aisbett E, Resosudarmo B, Baldwin KGH. Overcoming barriers to solar and wind energy adoption in two Asian giants: India and Indonesia. Energy Pol 2019;132:1216–28. https://doi.org/10.1016/j.enpol.2019.05.055.
[26] Setyowati AB. Mitigating energy poverty: mobilizing climate finance to manage the energy trilemma in Indonesia. Sustainability 2020;12. https://doi.org/10.3390/su12041603.
[27] Karra K, Kontgis C, Statman-Weil Z, Mazzariello JC, Mathis M, Brumby SP. Global land use/land cover with Sentinel 2 and deep learning. Igarss 2021 - 2021. IEEE int. Geosci. Remote Sens. Symp. 2021 Brussels.
[28] Ministry of Environment and Forestry. Land Cover Indonesia 2017. https://www.arcgis.com/sharing/rest/content/items/b1126d52d6c5416496339aeb250d9b39/info/metadata/metadata.xml?format=default&output=html (accessed September 13, 2021).
[29] GEBCO Compilation Group. GEBCO 2020 Grid 2020. https://doi.org/doi:10.5285/a29c5465-b138-234d-e053-6c86abc040b9.
[30] Ministry of Energy and Mineral Resources. Kebencanaan Geologi n.d. https://geoportal.esdm.go.id/monaresia/rest/services/4.GEOLOGI/Kebencanaan_Geologi/MapServer (accessed April 4, 2021).
[31] Pragt F. Assessment of the techno-economic potential of utility-scale solar PV in Indonesia and the effects of policy intervention. Delft University of Technology; 2021.
[32] Global Forest Watch. Indonesia peat lands 2016.

[33] World Port Source. Satellite Map of Ports Indonesia 2022. http://www.worldportsource.com/ports/IDN.php (accessed March 9, 2022).
[34] Ministry of Environment and Forestry. ArcGIS REST services of MoEF geoportal. 2017. https://geoportal.menlhk.go.id/arcgis/rest/services/KLHK_EN. [Accessed 4 April 2021].
[35] Geofabrik, OpenStreetMap. GEOFABRIK downloads. 2021. http://download.geofabrik.de/asia/indonesia.html. [Accessed 22 April 2022].
[36] Ministry of Energy. Mineral resources. Lokasi Gardu Induk 2022. https://geoportal.esdm.go.id/gis2/rest/services/djk_dpm/DJK_DPM_Sebaran_Lokasi_Gardu_Induk/MapServer. [Accessed 20 April 2022].
[37] Ministry of Energy. Mineral resources. Lokasi Sebaran Pembangkit Listrik 2022. https://geoportal.esdm.go.id/gis2/rest/services/djk_dpm/DJK_DPM_Sebaran_Lokasi_Pembangkit_Listrik/MapServer. [Accessed 22 April 2022].
[38] Sandia National Laboratories. PV_Lib Toolbox 2022. https://pvpmc.sandia.gov/applications/pv_lib-toolbox/(accessed April 29, 2022).
[39] CanadianSolar HiDM. High density mono PERC module 400W~420W. 2020. Ontario.
[40] Landau C. Optimum tilt of solar panels. 2017. http://www.solarpaneltilt.com/#fixed. [Accessed 17 June 2022].
[41] Siala K, Stich J. Estimation of the PV potential in ASEAN with a high spatial and temporal resolution. Renew Energy 2016;88:445–56. https://doi.org/10.1016/j.renene.2015.11.061.
[42] Solargis. Methodology. https://globalsolaratlas.info/support/methodology. [Accessed 12 September 2022].
[43] Energianalyse Ea. Prefeasibility studies of renewable projects in north Sulawesi. 2021. Copenhagen.
[44] International Energy Agency. Electricity transmission and distribution. 2014. Paris.
[45] Pojadas DJ, Abundo MLS. A spatial cost-benefit-externality modelling framework for siting of variable renewable energy farms: a case in Bohol, Philippines. Renew Energy 2022;181:1177–87. https://doi.org/10.1016/j.renene.2021.09.114.
[46] ://jualbetonc Jual Beton Cor. Daftar Harga Cor Beton Jalan Terbaru 2022. or.com/harga-cor-beton-jalan/, . [Accessed 17 June 2022].
[47] Levelized IESR. Cost of electricity in Indonesia. 2019. Jakarta.
[48] KPMG. Lombok - prefeasibility studies on RE solutions. 2019.
[49] National Energy Council. Technology data for the Indonesian power sector - catalogue for generation and storage of electricity. 2021. Jakarta.
[50] PricewaterhouseCoopers. Indonesian. Pocket tax book 2022. 2022. Jakarta.
[51] Inflation Data 2022 Indonesia Bank https://www.bi.go.id/en/statistik/indikator/data-inflasi.aspx. [Accessed 22 September 2022].
[52] International Energy Agency. Cost of Capital Observatory 2023. https://www.iea.org/reports/cost-of-capital-observatory/dashboard (accessed May 26, 2023).
[53] Bosch J, Staffell I, Hawkes AD. Temporally explicit and spatially resolved global offshore wind energy potentials. Energy 2018;163:766–81. https://doi.org/10.1016/j.energy.2018.08.153.
[54] Asian Development Bank. Guidelines for the economic analysis of projects. Mandaluyong City; 2017. https://doi.org/10.1177/003072707600900110.
[55] Persero) PTPLN(. Rencana usaha penyediaan tenaga listrik (RUPTL) 2021-2030. 2021. Jakarta.
[56] PricewaterhouseCoopers. Power in Indonesia. 2018. Jakarta.
[57] Peraturan Presiden Republik Indonesia. Percepatan pengembangan energi terbarukan untuk penyediaan listrik. 2022. Jakarta.
[58] Frisari G, Stadelmann M. De-risking concentrated solar power in emerging markets: the role of policies and international finance institutions. Energy Pol 2015;82:12–22. https://doi.org/10.1016/j.enpol.2015.02.011.
[59] Ministry of Energy and Mineral resources. Besaran Biaya Pokok Penyediaan Pembangkitan PT Perusahaan Listrik Negara (Persero) Tahun 2020 2021.
[60] Ojk OECD. Assessing progress of Indonesia ' s financial institutions towards the clean energy transition. 2022. Jakarta.
[61] Presiden republik Indonesia. Jakarta: Rencana Umum Energi Nasional; 2017.
[62] Ministry of Energy. Mineral resources. Statistik Ketenagalistrikan 2020 2021. Jakarta.
[63] Ministry of Energy. Mineral resources. Rencana Strategis 2020-2024 2020. Jakarta.
[64] Indonesia IESR. Solar energy outlook 2023. 2022. Jakarta.
[65] International Renewable Energy Agency. Renewable power generation costs in 2021. 2022. Jakarta.
[66] Langer J, Zaaijer M, Quist J, Blok K. Introducing site selection flexibility to technical and economic onshore wind potential assessments: new method with application to Indonesia. Renew Energy 2023;202:320–35. https://doi.org/10.1016/j.renene.2022.11.084.
[67] Suroyo G, Munthe BC. Indonesia introduces carbon trading policy to reduce emissions 2021. https://www.reuters.com/business/cop/indonesia-introduces-carbon-trading-policy-reduce-emission-2021-11-15/(accessed December 8, 2021).
[68] The World Bank. State and trends of carbon pricing 2021. 2021. https://doi.org/10.1596/978-1-4648-1728-1. Washington, D.C.
[69] Asian Development Bank. Renewable energy tariffs and incentives in Indonesia: review and recommendations. Mandaluyong City; 2020.
[70] Ministry of Energy. Mineral resources. Handb Energy & Econ Stat Indones 2021. Jakarta.
[71] Mararakanye N, Bekker B. Renewable energy integration impacts within the context of generator type, penetration level and grid characteristics. Renew Sustain Energy Rev 2019;108:441–51. https://doi.org/10.1016/j.rser.2019.03.045.
[72] Breyer C, Khalili S, Bogdanov D, Ram M, Oyewo AS, Aghahosseini A, et al. On the history and future of 100% renewable energy systems research. IEEE Access 2022;10:78176–218. https://doi.org/10.1109/ACCESS.2022.3193402.
[73] Abdellatif A, Mubarak H, Ahmad S, Ahmed T, Shafiullah GM, Hammoudeh A, et al. Forecasting photovoltaic power generation with a stacking ensemble model. Sustain Times 2022;14:1–21. https://doi.org/10.3390/su141711083.