The technical and economic potential of renewables in Indonesia and scenarios for power system decarbonisation

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The technical and economic potential of renewables in Indonesia and scenarios for power system decarbonisation

Dissertation

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by

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Summary

Abundant resources of coal have been at the centre of Indonesia's socio-economic development, covering almost two-thirds of electricity demand in 2022. Nonetheless, the government is aware of the negative local and global environmental effects of unabated fossil fuel combustion. Therefore, Indonesia is making efforts to transition away from coal to *Renewable Energy Technologies (RET)*, as embodied by the state-owned utility company PLN's green 10-year business plan and the *Just Energy Transition Partnership (JETP)* for the early retirement of coal-fired power plants and the investment in RET in Indonesia.

Literature suggests that Indonesia hosts large amounts of RET resources, or *potentials*, with which the energy transition could be propelled. In this context, RET potentials refer to the amount of electricity that could be generated from RET after filtering unsuitable geographic areas based on gradually more restrictive limitations, like nature conservation zones or built-up infrastructure. However, there are not yet thorough and consistent geographic RET potential maps for entire Indonesia that capture the variations in RET electricity generation in space and time. Most understanding currently stems from official sources with limited transparency and reproducibility that omit technologies like offshore wind and ocean energies. Furthermore, existing RET potentials do not yet address the technologies' economic feasibility under current and future circumstances. Thus, they do not acknowledge the significant economic barriers that RET face in Indonesia today. Lastly, existing RET potentials are not sufficiently embedded in Indonesia's complex power system. It remains unclear how a cost-effective, fully decarbonised power system might look like considering transmission grid topology, demand projections, variable RET productivity, and cost developments, amongst others. With these knowledge gaps, existing literature does not fully elucidate how Indonesia could transition away from coal in a cost-effective fashion and which RET's are most likely to replace coal.

Against this background, this dissertation sets out to answer the following main research question:

"What is the technical and economic potential of variable RET for power generation in Indonesia and how could RET contribute to a fully decarbonised power system?"

To answer the main research question, this dissertation maps the technical and economic potential of four variable RET, namely ground-mounted, utility-scale solar *photovoltaics (PV)*, onshore wind, offshore wind, and *Ocean Thermal Energy Conversion (OTEC)*. For all technologies, we use a *Geographic Information System (GIS)* approach to map technically feasible sites using publicly available, highly resolved global resource maps as well as maps reflecting the use and occupation of Indonesia's land and marine area. Then, we use power conversion models, e.g., wind farm and PV system models, to calculate the amount of generated electricity at the technically feasible sites, which embodies the technical RET potential. As such a detail power conversion model has not been available for OTEC, we developed our own open-source Python-based model to capture the spatial and temporal variability of ocean thermal energy resources. For the economic potential, we compute the *Levelised Cost of Electricity* per technically feasible site and compare the LCOEs with the tariffs to be received based on the then-applicable regulations. The economic potential encompasses the part of the technical potential for which LCOE are lower than or equal to the local tariff. To enhance the global relevance and scientific novelty of our work, we also perform further analyses relevant to each RET, e.g., a flexible site selection analysis that acknowledges the shared land use of onshore wind farms with agricultural areas and forests, and a financial analysis that addresses the bankability of utility-scale solar PV. After mapping the RET potentials, we use the spatially and temporally highly resolved energy system optimisation model Calliope to explore full decarbonisation scenarios for Indonesia's power sector. There, we model different decarbonisation pathways and perform a scenario and sensitivity analysis with varying transmission network topologies, demand projections, RET productivity, cost projections, and resource availabilities, to not only discern a set of diverse decarbonisation options, but also to detect overarching trends across these diverse solutions.

The technical potentials mapped in this dissertation amount to up to 22 PWh/year and could thus cover Indonesia's projected 2050 demand 7–23 times. Technical RET potentials are spread over almost all parts of Indonesia. However, bottlenecks exist, especially on Java. There, most land is already occupied by built-up infrastructure, forests, agricultural land, water bodies, conservation zones, and volcanoes. While some RET like onshore wind could be integrated into existing land uses with positive impacts on their technical and economic potentials, other RETs like ground-mounted, utility-scale PV cannot. For the latter RET, this leads to relatively small local technical potentials.

The economic potential of the four mapped RET reaches up to 4.3 PWh/year based on the regulations at the time of this dissertation, covering projected 2050 electricity demand 1.4–4.5 times. However, the economic potential is almost exclusively located on East Indonesia, where recent electricity tariffs were high, but current and projected electricity demand are low. Throughout this dissertation, we found that economic potentials could be increased and spread to the other parts of the country via different policies, e.g., a carbon tax of 100 US$/t$CO_2$e for onshore wind and feed-in tariff of 11.5 US¢/kWh for solar PV.

The table below summarises the technical and economic potentials mapped for this dissertation.

Summary of mapped technical and economic RET potentials.

Technology	Technical potential [TWh/year]	Economic potential [TWh/year]
Solar PV	12,200	3,400
Onshore wind	210–2,000	20–130
Offshore wind	6,800	750
OTEC	1,400	16
Total	**19,800–21,500**	**4,100–4,300**

There are several, diverse options for Indonesia to fully decarbonise their power system, with some being more cost-effective than others. The most cost-effective system configurations are achieved if Indonesia's economic centre of Java is connected to other islands via sub-sea power transmission lines. That is because Java would need to resort to novel, capital-intensive RET to cover demand locally. If demand grows more strongly than currently projected, technical RET resources on Java would not suffice anymore to secure supply. With 50 GW of inter-island transmission capacity, however, Indonesia can tap into its most-effective options, which are 468 GW of solar PV coupled with 172 GW of pumped hydroelectric energy storage, as well as at least 77 GW of baseload from biomass, geothermal, and reservoir hydropower. We also find that Indonesia's full power system decarbonisation could be achieved as early as 2040, provided that the process starts now.

We conclude that Indonesia is in a privileged position where it could choose between a broad range of possible solutions for their energy transition. Methodologically, we found RET potentials to be a powerful concept for the bookkeeping of technically and economically feasible resources. However, these RET potentials also proved to be sensitive to the used technical and economic inputs, so it is important to view them within the context of used assumptions and the power system they are embedded in. This dissertation offers valuable insights for those active in Indonesia's energy transition, including policymakers, capacity planners, RET developers, investors, and researchers. The methods and tools that were used, refined, and developed in this dissertation can be applied for any other computationally feasible regional scope, which makes our research globally relevant beyond Indonesia.

Although this dissertation succeeded in answering the main research questions, its limitations include a limited stakeholder engagement, the limited scope of socio-economic potentials on Indonesia's social welfare, and a limited focus on rural, off-grid RET systems. Our research recommendations for future work address the (1) mapping of RET that were omitted in this work, like rooftop solar PV and wave energy (e.g., along the Southern coast of Java), the (2) refinement of socio-economic potentials, e.g., via a cost-benefit analysis, and (3) further energy system modelling research for Indonesia and the region, e.g., addressing multi-energy sector-coupling, a regional supergrid across Southeast Asia, and the benefits and caveats of carbon capture and storage.

Moreover, our policy and industry recommendations comprise the (1) re-evaluation of current carbon neutrality pledges towards more ambitious target years, (2) standardisation of RET procurement processes of Indonesia's state-owned utility company PLN, (3) a legally binding official project pipeline for the roll-out of mature RET and the commercialisation of early-stage RET like low-wind-speed offshore wind and OTEC, as well as the (4) development of a solar PV strategy to tap into the technology's large potential for cost-effective power system decarbonisation.

Samenvatting

De grote steenkoolvoorraden hebben een cruciale rol gespeeld in de sociaaleconomische ontwikkeling van Indonesië, waarbij ze bijna tweederde van de elektriciteitsvraag in 2022 hebben voorzien. Desondanks is de overheid zich bewust van de negatieve lokale en wereldwijde milieueffecten van de verbranding van fossiele brandstoffen. Daarom doet Indonesië inspanningen om over te stappen van steenkool naar hernieuwbare energie technologieën (*Renewable Energy Technologies - RET*), zoals beschreven in het groene tienjarige bedrijfsplan van het staatsbedrijf voor nutsvoorzieningen PLN en het *Just Energy Transition Partnership (JETP)* voor de vervroegde uittreding van kolengestookte energiecentrales en de investering in RET in Indonesië.

De literatuur suggereert dat Indonesië beschikt over grote hoeveelheden RET-bronnen, oftewel RET-potentieel, waarmee de energietransitie kan worden versneld. In deze context verwijzen RET-potentieel naar de hoeveelheid elektriciteit die uit RET kan worden opgewekt na het uitfilteren van ongeschikte geografische gebieden op basis van geleidelijk restrictievere beperkingen, zoals natuurbehoudszones of bebouwde infrastructuur. Er zijn echter nog geen grondige en consistente geografische kaarten van RET-potentieel voor heel Indonesië die de variaties in RET-elektriciteitsopwekking in ruimte en tijd weergeven. Het meeste inzicht komt momenteel voort uit officiële bronnen met beperkte transparantie en reproduceerbaarheid, waarin technologieën zoals offshore wind- en oceaanenergieën buiten beschouwing worden gelaten. Bovendien adresseren bestaande RET-potentieel nog niet de economische haalbaarheid van de technologieën onder huidige en toekomstige omstandigheden. Ze erkennen dus niet de significante economische barrières waarmee RET vandaag de dag in Indonesië worden geconfronteerd. Tot slot zijn bestaande RET-potentieel niet voldoende ingebed in het complexe elektriciteitssysteem van Indonesië. Het blijft onduidelijk hoe een kosteneffectief, volledig gedecarboniseerd elektriciteitssysteem eruit zou kunnen zien, rekening houdend met, onder andere, de topologie van het transmissienet, vraagprognoses, variabele RET-productiviteit en kostenontwikkelingen. Met deze kenniskloven verschaft de bestaande literatuur niet volledig duidelijkheid over hoe Indonesië op een kosteneffectieve manier zou kunnen afstappen van steenkool en welke RET's het meest waarschijnlijk steenkool zullen vervangen.

Tegen deze achtergrond heeft dit proefschrift tot doel de volgende hoofdonderzoeksvraag te beantwoorden:

“Wat is het technische en economische potentieel van variabele RET voor elektriciteitsopwekking in Indonesië en hoe zou RET kunnen bijdragen aan een volledig gedecarboniseerd elektriciteitssysteem?”

Om de hoofdonderzoeksvraag te beantwoorden, brengt dit proefschrift het technische en economische potentieel van vier variabele RET in kaart, namelijk op de grond gemonteerde fotovoltaïsche zonnepanelen (PV) op utiliteitsschaal, onshore windenergie, offshore windenergie en Ocean Thermal Energy Conversion (OTEC). Voor alle technologieën gebruiken we een Geografisch Informatie Systeem (GIS)-benadering om technisch haalbare locaties in kaart te brengen met behulp van openbaar beschikbare, hoogwaardige mondiale hulpbronnenkaarten, evenals kaarten die het gebruik en de bezetting van het land- en zeegebied van Indonesië weerspiegelen. Vervolgens gebruiken we modellen voor elektriciteitsconversie, bijvoorbeeld windpark- en PV-systeemmodellen, om de hoeveelheid opgewekte elektriciteit op de technisch haalbare locaties te berekenen, wat het technische RET-potentieel aangeeft. Aangezien een dergelijk gedetailleerd elektriciteitsconversiemodel voor OTEC niet beschikbaar was, hebben we ons eigen open-source Python-gebaseerde

model ontwikkeld om de ruimtelijke en temporele variabiliteit van de oceaan thermische energiebronnen vast te leggen. Voor het economisch potentieel berekenen we de Levelised Cost of Electricity (LCOE) per technisch haalbare locatie en vergelijken we de LCOE's met de te ontvangen tarieven op basis van de toen geldende regelgeving. Het economisch potentieel omvat het deel van het technisch potentieel waarvoor de LCOE lager of gelijk is aan het lokale tarief. Om de wereldwijde relevantie en wetenschappelijke vernieuwing van ons werk te verbeteren, voeren we ook verdere analyses uit die relevant zijn voor elke RET, bijvoorbeeld een flexibele locatieselectieanalyse die het gedeelde landgebruik van onshore windparken met landbouwgebieden en bossen erkent, en een financiële analyse die zich richt op de financierbaarheid van zonne-energie op utiliteitsschaal. Na het in kaart brengen van de RET-potentieel gebruiken we het ruimtelijk en temporeel zeer gedetailleerde energie-optimalisatiemodel Calliope om volledige decarbonisatiescenerio's te verkennen voor de elektriciteitssector van Indonesië. Daar modelleren we verschillende decarbonisatietrajecten en voeren we een scenario- en gevoeligheidsanalyse uit met variërende topologieën van transmissienetwerken, vraagprognoses, RET-productiviteit, kostenprognoses en beschikbaarheid van hulpbronnen, om niet alleen een reeks uiteenlopende decarbonisatie-opties te onderscheiden, maar ook om overkoepelende trends te detecteren tussen deze diverse oplossingen.

De technische potenties die in dit proefschrift in kaart zijn gebracht, bedragen tot 22 PWh/jaar en zouden daarmee de geprojecteerde vraag van Indonesië in 2050 7 tot 23 keer kunnen dekken. Technische RET-potentieel zijn verspreid over bijna alle delen van Indonesië. Er zijn echter knelpunten, vooral op Java. Daar is het grootste deel van het land al bezet door bebouwde infrastructuur, bossen, landbouwgrond, watermassa's, natuurbehoudszones en vulkanen. Hoewel sommige RET, zoals onshore wind, kunnen worden geïntegreerd in bestaand grondgebruik met positieve gevolgen voor hun technische en economische potentieel, kunnen andere RET's, zoals op de grond gemonteerde PV zonnepanelen op utiliteitsschaal, dat niet doen. Voor deze laatste RET leidt dit tot relatief kleine lokale technische potenties.

Het economische potentieel van de vier in kaart gebrachte RET reikt tot 4,3 PWh/jaar op basis van de regelgeving ten tijde van dit proefschrift, en dekt daarmee de geprojecteerde elektriciteitsvraag voor 2050 1,4 tot 4,5 keer. Het economische potentieel situeert zich echter vrijwel uitsluitend in Oost-Indonesië, waar de recente elektriciteitstarieven hoog waren, maar de huidige en geprojecteerde elektriciteitsvraag laag is. Gedurende dit proefschrift hebben we vastgesteld dat economische potenties kunnen worden vergroot en verspreid naar andere delen van het land via verschillende beleidsmaatregelen, zoals een koolstofbelasting van 100 US$/tCO2e voor onshore wind en een feed-in-tarief van 11.5 US¢/kWh voor PV zonnepanelen.

The tabel hieronder vat de technische en economische potenties samen die zijn vastgesteld voor dit proefschrift.

Samenvatting van de in kaart gebrachte technische en economische RET-potentieel.

Technologie	Technisch potentieel [TWh/jaar]	Economisch potentieel [TWh/jaar]
PV Zonnepanelen	12,200	3,400
Onshore wind	210–2,000	20–130
Offshore wind	6,800	750
OTEC	1,400	16
Totaal	**19,800–21,500**	**4,100–4,300**

Er zijn verschillende, uiteenlopende opties voor Indonesië om zijn energiesysteem volledig te decarboniseren, waarbij sommige kosteneffectiever zijn dan andere. De meest kosteneffectieve systeemconfiguraties worden bereikt als het economische centrum van Indonesië, Java, wordt verbonden met andere eilanden via onderzeese elektriciteitstransmissielijnen. Dat komt doordat Java anders zou moeten investeren in nieuwe, kapitaalintensieve RET om lokaal aan de vraag te voldoen. Als de vraag sterker groeit dan momenteel geprojecteerd, zouden technische RET-bronnen op Java niet meer volstaan om de levering te waarborgen. Met 50 GW aan transmissiecapaciteit tussen de eilanden kan Indonesië echter profiteren van zijn meest effectieve opties, namelijk 468 GW_p aan PV zonnepanelen gekoppeld aan 172 GW aan gepompte waterkrachtopslag, evenals minstens 77 GW aan baseload uit biomassa, geothermische energie en reservoir-hydropower. We constateren ook dat het volledig decarboniseren van het Indonesische elektriciteitssysteem al in 2040 kan worden bereikt, op voorwaarde dat het proces nu begint.

We concluderen dat Indonesië zich in een bevoorrechte positie bevindt waar het kan kiezen uit een breed scala aan mogelijke oplossingen voor zijn energietransitie. Methodologisch gezien vonden we dat RET-potentieel een krachtig concept is voor het boekhouden van technisch en economisch haalbare hulpbronnen. Echter, deze RET-potentieel bleken ook gevoelig te zijn voor de gebruikte technische en economische input, dus het is belangrijk om ze te bekijken binnen de context van de gebruikte aannames en het elektriciteitssysteem waarin ze zijn ingebed. Dit proefschrift biedt waardevolle inzichten voor degenen die actief zijn in de Indonesische energietransitie, waaronder beleidsmakers, capaciteitsplanners, RET-ontwikkelaars, investeerders en onderzoekers. De methoden en tools die in dit proefschrift zijn gebruikt, verfijnd en ontwikkeld, kunnen worden toegepast op elke andere computationeel haalbare regionale reikwijdte, wat ons onderzoek mondiaal relevant maakt naast Indonesië.

Hoewel dit proefschrift erin is geslaagd om de belangrijkste onderzoeksvragen te beantwoorden, omvatten de beperkingen een beperkte betrokkenheid van belanghebbenden, de beperkte reikwijdte van sociaaleconomische potentialen over de sociale welvaart van Indonesië, en een beperkte focus op landelijke, off-grid RET-systemen. Onze onderzoeksaanbevelingen voor toekomstig werk hebben betrekking op (1) het in kaart brengen van RET die in dit werk buiten beschouwing zijn gelaten, zoals PV zonnepanelen op daken en golfenergie (bijvoorbeeld langs de zuidkust van Java), (2) de verfijning van sociaaleconomische potentialen, bijvoorbeeld via een kosten-batenanalyse, en (3) verder onderzoek naar modellering van energiesystemen voor Indonesië en de regio, bijvoorbeeld het adresseren van multi-energie sector-koppeling, een regionaal supergrid in heel Zuidoost-Azië, en de voordelen en kanttekeningen van koolstofopvang en -opslag.

Bovendien omvatten onze beleids- en industriële aanbevelingen de (1) herziening van de huidige toezeggingen op het gebied van koolstofneutraliteit in de richting van ambitieuzere streefjaren, (2) standaardisatie van RET-inkoopprocessen van het Indonesische staatsbedrijf PLN, (3) een wettelijk bindende officiële projectpijplijn voor de uitrol van volwassen RET en de commercialisering van RET die nog in een vroeg ontwikkelingsstadium zijn, zoals offshore wind met lage windsnelheid en OTEC, evenals (4) de ontwikkeling van een strategie voor PV zonnepanelen om het grote potentieel van de technologie te benutten voor een kosteneffectieve decarbonisatie van het elektriciteitssysteem.

Ringkasan

Sumber daya batu bara yang melimpah telah menjadi fokus pembangunan ekonomi sosial di Indonesia, di mana batu bara memenuhi hampir dua pertiga kebutuhan listrik Indonesia pada tahun 2022. Meskipun demikian, pemerintah Indonesia menyadari dampak negatif terhadap lingkungan baik lokal maupun global akibat penggunaan bahan bakar fosil yang terus berlanjut. Oleh karena itu, Indonesia melakukan usaha untuk beralih dari batu bara ke sumber energi terbarukan (SET)*[1], sebagaimana diwujudkan dalam Rencana Usaha Penyediaan Tenaga Listrik (RUPTL) yang lebih hijau oleh PLN dan Just Energy Transition Partnership (JETP), sebuah kemitraan yang ditujukan untuk membantu Indonesia mempercepat pemensiunan dini pembangkit listrik berbasis batubara dan investasi pada SET di Indonesia.

Studi pustaka menunjukkan bahwa Indonesia memiliki potensi SET dalam jumlah besar yang dapat digunakan untuk mendorong transisi energi. Dalam hal ini, potensi SET mengacu pada jumlah listrik yang dapat dihasilkan oleh suatu SET setelah memilah wilayah geografis yang tidak sesuai berdasarkan pada syarat pengecualian yang secara bertahap menjadi lebih ketat, seperti kawasan konservasi alam atau infrastruktur yang telah dibangun. Namun, hingga saat ini belum ada peta geografis potensi SET yang menyeluruh dan mencakup seluruh wilayah Indonesia yang mampu menangkap variasi pembangkitan listrik SET dalam ruang dan waktu. Sebagian besar pemahaman saat ini berasal dari sumber resmi dengan tingkat transparansi dan kemungkinan reproduksi yang terbatas serta tanpa menyertakan teknologi seperti energi angin lepas pantai dan energi laut. Selain itu, penelitian-penelitian mengenai potensi SET belum menjawab permasalah kelayakan ekonomi dari teknologi-teknologi tersebut dalam situasi di masa kini dan masa mendatang. Oleh sebab itu, penelitian-penelitian tersebut juga belum mengakui hambatan ekonomi signifikan yang dihadapi oleh SET di Indonesia saat ini. Yang terakhir, potensi SET yang telah ada tidak cukup terlibat dalam sistem ketenagalistrikan Indonesia yang kompleks. Masih belum jelas bagaimana bentuk sistem ketenagalistrikan yang hemat biaya dan ter-dekarbonisasi sepenuhnya, dengan mempertimbangkan antara lain topologi jaringan listrik, proyeksi pertumbuhan permintaan listrik, produksi SET yang bervariasi, dan perkembangan biaya. Dengan adanya kesenjangan pengetahuan tersebut, pustaka yang ada saat ini belum dapat menjelaskan bagaimana Indonesia dapat beralih dari batubara secara hemat biaya dan SET mana yang paling mungkin menggantikan batubara.

Dengan latar belakang tersebut, disertasi ini bertujuan untuk menjawab pertanyaan penelitian berikut:

Berapa potensi teknis dan ekonomi dari berbagai SET untuk pembangkit listrik di Indonesia dan bagaimana SET dapat berkontribusi untuk sistem ketenagalistrikan yang sepenuhnya ter-dekarbonisasi?

Untuk menjawab pertanyaan penelitian tersebut, disertasi ini memetakan potensi teknis dan ekonomi dari empat SET yaitu tenaga surya fotovoltaik skala utilitas yang dipasang di permukaan tanah, tenaga bayu, tenaga bayu lepas pantai, dan energi panas laut (*Ocean Thermal Energy Conversion*/OTEC). Untuk semua teknologi, kami menggunakan pendekatan Sistem Informasi Geografis (SIG) untuk memetakan lokasi-lokasi yang layak secara teknis, dengan menggunakan peta sumber daya global serta peta-peta khusus yang menampilkan

[1] *Penulis dengan sengaja tidak menulis "energi baru terbarukan" atau EBT, sebab menurut Rancangan Undang-undang (RUU) Energi Baru Terbarukan (EBT) Pasal 1 Ayat 2, "Energi Baru adalah semua jenis Energi yang berasal dari atau dihasilkan dari teknologi baru pengolahan sumber Energi tidak terbarukan dan sumber Energi terbarukan.". Dalam disertasi ini, penulis hanya berfokus pada sumber energi terbarukan (SET).*

pemanfaatan ruang darat maupun laut di Indonesia. Peta yang digunakan adalah peta yang tersedia untuk umum dan memiliki resolusi yang tinggi. Kemudian, kami menggunakan model konversi daya, misalnya model ladang angin dan sistem fotovoltaik, untuk menghitung jumlah listrik yang dihasilkan dalam area yang layak secara teknis. Hasil perhitungan ini adalah potensi teknis SET. Model konversi daya yang terperinci belum tersedia untuk OTEC, kami mengembangkan sendiri model sumber terbuka (*open source*) berbasis Python yang dapat menganalisis variabilitas spasial dan temporal dari sumber daya energi panas laut. Untuk potensi ekonomi, kami menghitung *levelised cost of electricity*[2] (LCOE) untuk setiap lokasi yang layak dan membandingkan LCOE tersebut dengan harga jual listrik yang akan diterima sesuai peraturan yang berlaku. Potensi ekonomi mencakup sebagian dari potensi teknis di mana LCOE untuk suatu lokasi lebih rendah atau sama dengan harga jual listrik di wilayah tersebut. Untuk meningkatkan relevansi global dan kebaruan ilmiah dari penelitian kami, kami juga melakukan analisis lebih lanjut yang relevan untuk tiap-tiap SET. Sebagai contoh, analisis pemilihan lokasi yang dapat disesuaikan berdasarkan kemungkinan penggunaan bersama antara ladang angin darat dengan kawasan pertanian dan perhutanan. Contoh lainnya yaitu analisis keuangan yang menangani isu bankability dari tenaga surya fotovoltaik skala utilitas. Setelah memetakan potensi SET, kami menggunakan model optimasi sistem energi dengan resolusi spasial dan temporal yang tinggi bernama Calliope untuk mengeksplorasi skenario-skenario dekarbonisasi penuh sektor ketenagalistrikan Indonesia. Di sini kami memodelkan berbagai rancangan jalur dan mengaplikasikan analisis skenario dan sensitivitas dengan bermacam-macam topologi jaringan transmisi, proyeksi permintaan, produktivitas SET, proyeksi biaya, dan ketersediaan sumber daya. Hal ini kami lakukan tidak hanya untuk mempertimbangkan serangkaian pilihan dekarbonisasi yang beragam, namun juga untuk mendeteksi tren umum di beragam solusi tersebut.

Potensi teknis SET yang dipetakan dalam disertasi ini mencapai 22 PWh/tahun, jumlah yang dapat memenuhi proyeksi permintaan listrik Indonesia pada tahun 2050 sebesar 7-23 kali lipat. Potensi teknis SET tersebut tersebar di seluruh wilayah Indonesia. Namun demikian, terdapat beberapa hambatan, terutama di Pulau Jawa. Di sana, sebagian besar lahan telah terisi oleh berbagai fungsi ruang, seperti prasarana fisik, kawasan perhutanan, lahan pertanian, badan air, zona konservasi alam, dan gunung berapi. Beberapa SET seperti tenaga bayu dapat diintegrasikan ke dalam penggunaan lahan yang ada dan menghasilkan dampak positif terhadap potensi teknis dan ekonominya. Namun demikian, SET lainnya seperti tenaga surya fotovoltaik skala utilitas yang dipasang di permukaan tanah tidak dapat diintegrasikan. Hal ini menyebabkan potensi teknis lokal yang relatif rendah.

Potensi ekonomi dari keempat SET yang dipetakan mencapai 4.3 PWh/tahun berdasarkan peraturan yang berlaku pada saat disertasi ini ditulis. Potensi ini dapat memenuhi proyeksi permintaan listrik Indonesia tahun 2050 sebesar 1.4-4.5 kali lipat. Sayangnya, potensi ekonomi ini hampir seluruhnya terletak di Indonesia bagian Timur, di mana harga jual listrik saat ini tinggi walaupun permintaan listrik saat ini dan di masa depan diperkirakan rendah. Dari penelitian ini, kami menemukan bahwa potensi ekonomi dapat ditingkatkan dan disebarkan ke wilayah lain di Indonesia melalui kebijakan yang berbeda, misalnya dengan pajak karbon sebesar 100 US$/t$CO_2$e untuk tenaga bayu dan feed-in tariff sebesar 11.5 US¢/kWh untuk tenaga surya fotovoltaik.

Tabel di bawah merangkum potensi teknis dan ekonomi yang dipetakan dalam disertasi ini.

[2] *nilai rata-rata biaya yang dikeluarkan untuk energi listrik yang dihasilkan oleh suatu aset selama masa pakainya*

Rangkuman potensi teknis dan ekonomi SET yang dipetakan

Teknologi	Potensi teknis [TWh/tahun]	Potensi ekonomi [TWh/tahun]
Tenaga surya fotovoltaik	12,200	3,400
Tenaga bayu (darat)	210–2,000	20–130
Tenaga bayu lepas pantai	6,800	750
Energi panas laut (OTEC)	1,400	16
Total	**19,800–21,500**	**4,100–4,300**

Indonesia memiliki beragam pilihan untuk melakukan dekarbonisasi sistem ketenagalistrikan nasional, di mana sebagian pilihan lebih hemat biaya dibandingkan yang lainnya. Konfigurasi sistem yang paling hemat biaya dapat dicapai jika Pulau Jawa, sebagai pusat perekonomian Indonesia, terhubung ke pulau-pulau lain melalui jalur transmisi listrik bawah laut. Hal ini disebabkan oleh perlunya penggunaan SET baru yang padat modal untuk memenuhi permintaan lokal di Pulau Jawa. Jika permintaan listrik tumbuh lebih tinggi dari perkiraan saat ini, sumber daya teknis SET di Pulau Jawa tidak akan mencukupi untuk memenuhinya. Dengan kapaitas transmisi antar pulau sebesar 50 GW, Indonesia dapat memanfaatkan pilihan yang paling efektif, yaitu 468 GW pembangkit listrik tenaga surya (PLTS) fotovoltaik ditambah dengan 172 GW pembangkit listrik tenaga air (PLTA) *pumped storage*, serta setidaknya 77 GW beban dasar dari biomassa, panas bumi, dan PLTA. Kami juga menemukan bahwa dekarbonisasi penuh sistem ketenagalistrikan Indonesia dapat dicapai pada tahun 2040, jika prosesnya dimulai saat ini.

Kami menyimpulkan bahwa Indonesia berada dalam posisi istimewa di mana Indonesia memiliki berbagai pilihan solusi untuk melakukan transisi energi. Secara metodologis, kami menemukan bahwa perhitungan potensi SET adalah konsep yang kuat untuk menginventarisasi sumber daya yang layak secara teknis dan ekonomi. Di sisi lain, analisis ini juga terbukti sensitif terhadap input teknis dan ekonomi yang digunakan, sehingga penting untuk melihatnya dalam konteks dengan asumsi yang digunakan dan sistem ketenagalistrikan di mana analisis ini dilakukan. Disertasi ini menawarkan wawasan berharga bagi mereka yang aktif berkiprah dalam transisi energi di Indonesia, termasuk pembuat kebijakan, perencana kapasitas, pengembang teknologi SET, investor, dan peneliti. Metode dan instrumen penelitian yang dikembangkan dalam disertasi ini dapat diterapkan pada lingkup regional lain, sehingga menjadikan penelitian kami relevan secara global di luar Indonesia.

Meskipun pertanyaan-pertanyaan penelitian telah berhasil dijawab, disertasi ini memiliki beberapa keterbatasan. Keterbatasan disertasi ini di antara lain yaitu terbatasnya keterlibatan pemangku kepentingan, terbatasnya cakupan dampak potensi sosio ekonomi terhadap kesejahteraan sosial Indonesia, dan terbatasnya perhatian pada sistem SET di pedesaan dan di luar jaringan listrik. Untuk penelitian di masa depan, kami merekomendasikan (1) pemetaan SET lain yang tidak dibahas dalam penelitian ini, seperti panel surya atap dan energi gelombang laut (contohnya di sepanjang pesisir Selatan Pulau Jawa), (2) penyempurnaan analisis potensi sosioekonomi, misalnya melalui analisis biaya manfaat (*cost benefit analysis*), dan (3) penelitian lebih lanjut mengenai pemodelan sistem ketenagalistrikan di Indonesia dan kawasan Asia Tenggara, misalnya mengenai multi-energy sector-coupling, supergrid regional Asia Tenggara, dan kekurangan serta kelebihan dari penangkapan dan penyimpanan karbon.

Selain ini, kami memiliki beberapa rekomendasi bagi pengambil kebijakan dan sektor industri, yaitu (1) evaluasi ulang komitmen netralitas karbon saat ini menuju tahun target yang lebih ambisius, (2) standarisasi proses pengadaan SET dari PLN, (3) *project pipeline* resmi yang terikat secara hukum untuk peluncuran teknologi SET yang telah matang dan komersialisasi teknologi SET tahap awal seperti tenaga angin lepas pantai berkecepatan rendah dan OTEC, dan (4) pengembangan strategi tenaga surya fotovoltaik untuk memanfaatkan potensi besar teknologi tersebut bagi dekarbonisasi sistem tenaga listrik yang hemat biaya.

1. Introduction

1. Background

Indonesia is a country of riches. Its more than 14,000 islands not only host a variety of cultural and culinary delights, but also a treasure trove of natural resources, including gold [1]. But depending on who you ask, the answer to what gold is may differ. Most people will probably think of the metal that ornaments their necks and fingers. But some might think of something less shiny. Something they would call the “black gold” [2]: coal.

Sourced from the mines of Kalimantan and Sumatera [3], coal has been the fuel of Indonesia’s development. As shown in Figure 1, Indonesia’s demand for electricity has been rising steadily over the last years. Almost three-quarters of demand came from Java and Bali [1], and coal provided 62% of total electricity production in 2022 [3]. Seen as a “backbone of [the] national economy” [4, p.7], earlier official programs, like the national energy plan (*Rencana Umum Energi Nasional – RUEN)* [5], would have manifested coal’s dominance for decades in the name of socio-economic development, with a projected fossil-fuelled capacity of 275 GW, or 62% of total capacity, in 2050.

However, promoting development via coal comes at a price. The combustion of coal releases pollutants, like CO_2 and particulate matter, that cause harm both locally and globally. The air quality in Indonesia’s capital Jakarta is one of the worst in the world and triggered a public health crisis in 2023. Seen as one of the culprits, the production of the neighbouring coal plant Suralaya was temporarily reduced by roughly 50%, from 3.4 to 1.8 GW [6]. Moreover, Indonesia belongs to the world’s top 10 CO_2 emitting countries and thus contributes significantly to climate change via global warming [7].

The Indonesian government and state-owned utility company PLN are aware of the catastrophic impact that unabated global warming would have on the country. Over the last few years, the energy transition, or more specifically the shift from coal to *Renewable Energy Technologies (RET)*, became increasingly prominent. In 2021, Indonesia pledged to become carbon neutral by 2060 or earlier [8], underlined by PLN’s most ambitious 10-year business plan (*Rencana Usaha Penyediaan Tenaga Listrik – RUPTL)* [9] in terms of RET implementation. More recently, Indonesia, the EU, and International Partners Group launched the Just Energy Transition Plan, with which Indonesia is to receive US$ 20 billion for the retirement of coal plants and development of RET [10].

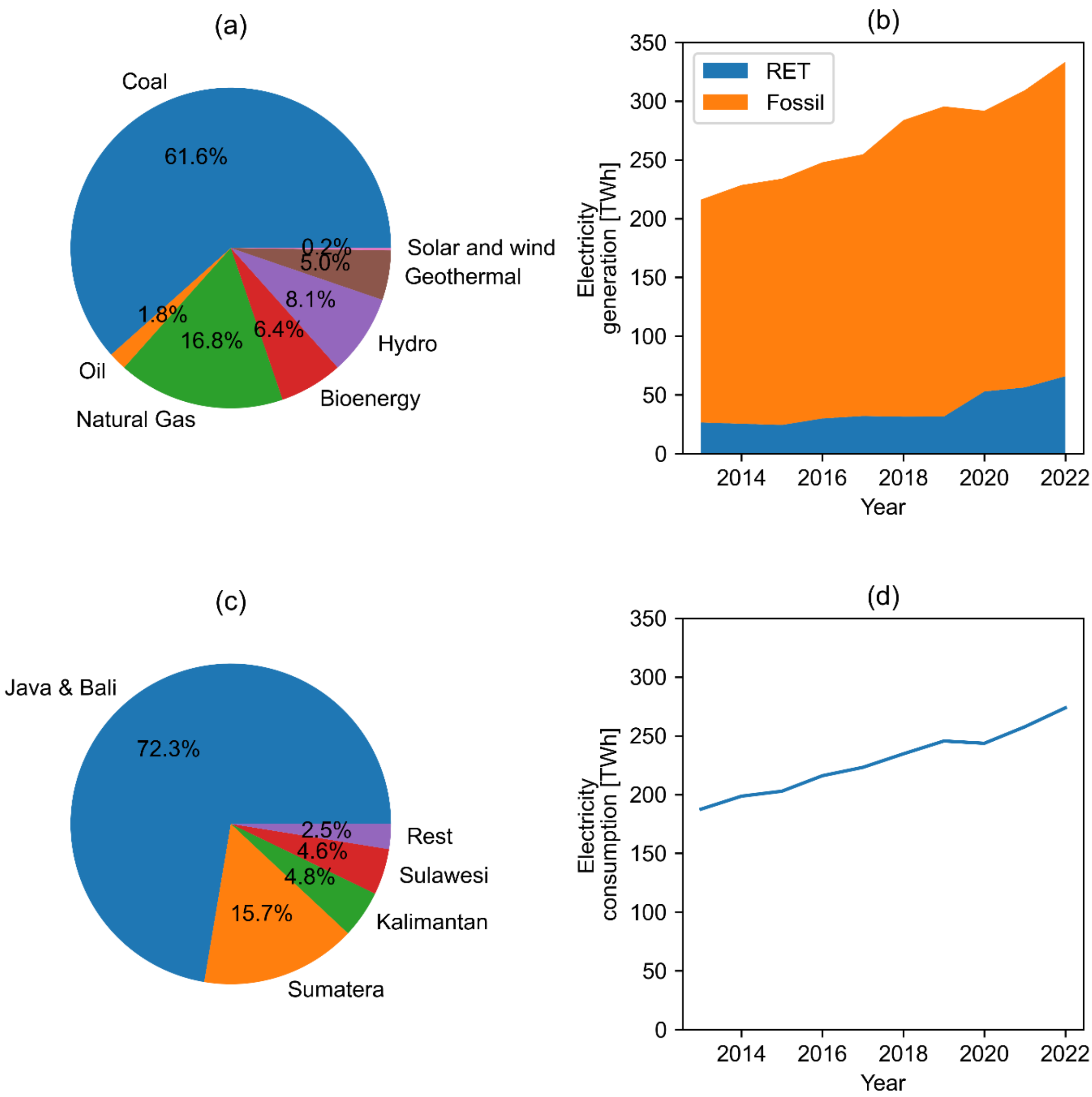

Figure 1. Overview of Indonesia's electricity system, showing (a) the electricity generation per technology in 2022, (b) electricity generation by RET and fossil-fuelled generators from 2013–2022, (c) electricity consumption per island in 2020, and (d) development of electricity consumption from 2013–2022 [1,3].

2. Renewable Energy Potentials

What plays into Indonesia's hands in achieving such an ambitious transition is the amount and diversity of its RET resources on land and sea. In literature [11–13], the energy content of these resources and the amount of electricity that can be produced with them is referred to as *potential*. There are different types of potentials as shown in Figure 2, which become increasingly refined and practically relevant using technical and economic criteria, amongst others. The theoretical (or resource) potential describes the primary energy content of a resource only restricted by physical limits. The technical potential is the amount of electricity that can be produced from the theoretical potential after accounting for conversion losses as well as (non-)technical constraints, for example from land use. The economic potential is the part of the technical potential for which benefits exceed costs, which can be further divided into the socio-economic and bankable potential. The socio-economic potential reflects the economically feasible part of the technical potential where costs are considered from the public perspective, whereas the bankable potential encompasses the part of the technical potential for which sufficient funding can be acquired and profits generated with costs considered from a private perspective. We only map the bankable potential in chapter 5 for solar PV and focus on the socio-economic potential in the other chapters. For simplicity, we refer to the socio-economic potential as *economic potential* in these chapters.

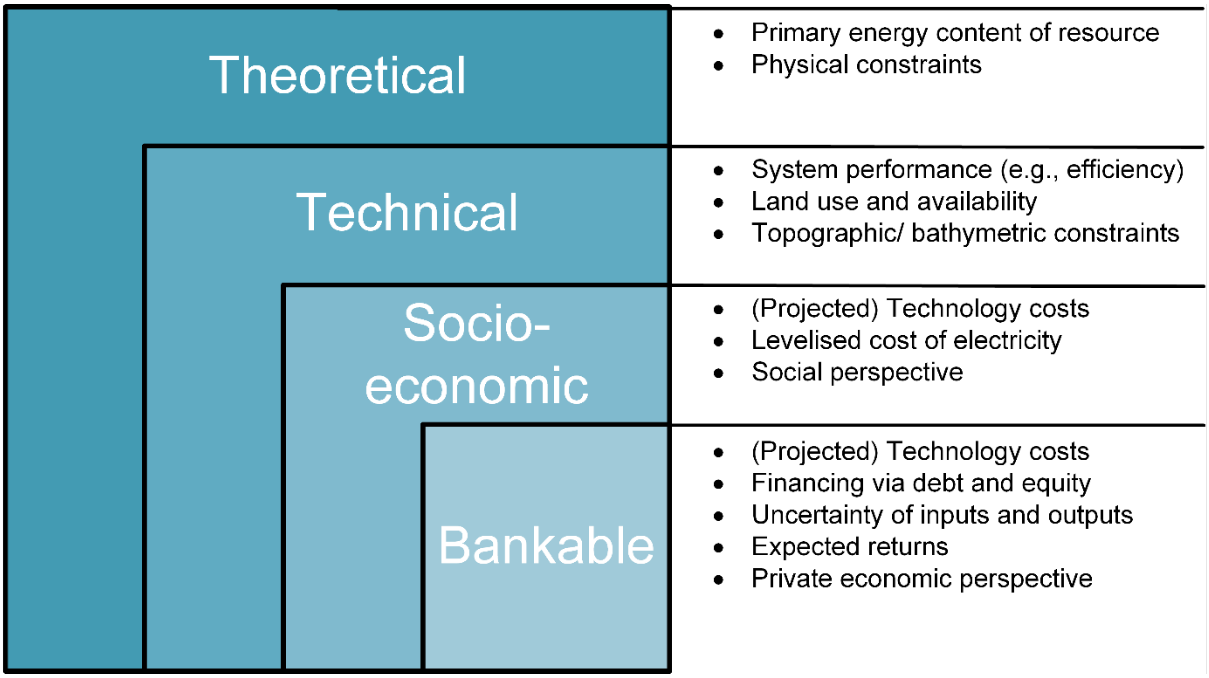

Figure 2. Levels of potentials and their definitions. Visualisation, terms, and definitions based on Refs. [11–13].

RET potential maps are useful as they provide an inventory of technically and economically available resources and their location. In Indonesia, RET potentials have been mapped by the Ministry of Energy and Mineral Resources *(Kementerian Energi dan Sumber Daya Mineral – ESDM)* and used for official plans, like RUEN [5].

As reviewed further in chapter 2, academic and non-academic literature also mapped RET potentials in Indonesia, amongst others for solar *photovoltaics (PV)* [14,15], wind power [16,17], and *Ocean Thermal Energy Conversion (OTEC)* [18]. OTEC is a promising early-stage RET that uses the temperature difference between warm surface and cold deep-seawater to produce electricity. Based on work preceding this dissertation [19], fully developed OTEC would have several benefits over other RET, including baseload production at competitive generation costs as well as lower land requirements. Given the excellent prerequisites for OTEC in Indonesia [18], this dissertation explores OTEC's role there further.

3. Energy system modelling

The RET potentials mapped in this dissertation provide valuable information about the location of RET resources as well as the amount, variability, and costs of the electricity produced by them. However, these potentials do not yet reveal whether they can meet future electricity demand in all parts of Indonesia at any given moment in time, which electricity system configurations are the most cost-effective, and until when full electricity system decarbonisation could be feasible. To address these questions, the potentials are used as inputs to energy system models. Such models can have different purposes, but for this dissertation we focus on models for long-term capacity planning.

Energy system models are mathematical models, with which the existing energy system can be replicated in the user's desired and computationally feasible detail, and future system configurations can be explored. Historically, the key themes of energy system modelling were energy security and costs in the wake of the global oil crisis in the 1970's [20]. Although these themes remain important today, the focus has shifted towards climate change mitigation and the modelling of future systems with high or even 100% shares of RET [21]. Given the spatial and temporal variability of some RET, energy system models evolved towards capturing these fluctuations, e.g., PyPSA [22], Calliope [23], and LUT-ESTM [21]. Moreover, these models can reflect the increasingly important coupling of the power, industrial, and transportation sectors and consequent exchange and conversion of energy carriers like electricity, heat, and fuels.

In Indonesia, energy system models have been used in academic and non-academic literature, as well as for official documents, such as RUEN [5], RUPTL [9], and Indonesia Energy Outlook [24]. Commonly used models include LEAP [25,26], PLEXOS [27], LUT [28,29], and Balmorel [24,30,31].

4. Problem statement and motivation

There is already a broad body of literature on RET potential mapping and energy system modelling for Indonesia. But in light of the concepts introduced so far, we detected several knowledge gaps that motivate this dissertation. They mostly pertain to the challenges variable RET introduce to fossil-based electricity systems as well as to overarching trends in research, like open science.

There is a lack of RET potential maps that specifically focus on the entire country of Indonesia. Many works either focus on the subnational level, like West Kalimantan [32] and Bali [33], or the global level with Indonesia being a part of the analysis [34,35]. For the former, the local results might not be scalable to the entire country given Indonesia's size and diversity. For the latter, datasets of low spatial and temporal resolution are usually necessary to operationalise the global analysis, which leads to a lower accuracy of RET potential estimations.

Most work on RET potential mapping has been done by Indonesia's Ministry of Energy and Mineral Resources ESDM. However, the methods and data used to determine these potentials are mostly not elaborated on and some of them might not be up-to-date anymore. Furthermore, these potentials exclude RET that are less mature in Indonesia and in general, like offshore wind and OTEC.

Another limitation that applies to ESDM's work and general Indonesian RET mapping literature is the lack of research of economic potentials. Besides some exceptions [15,32], most existing studies pertain to the theoretical and technical level and do not perform an economic analysis. Therefore, it remains unclear how RET's economic potential has been affected by its costs and existing support schemes, and how it could be further refined by policies, like a carbon tax and feed-in tariffs.

Lack of spatial and temporal resolution is also a shortcoming of Indonesian energy modelling literature. Most existing works do not consider the spatial and temporal fluctuations of RET power production and electricity demand. Moreover, they deploy a copperplate approach, meaning that all electricity generation and consumption occurs in one single node, and, if at all, use a constant, location-independent power transmission efficiency [25,36,37]. This does not reflect Indonesia's transmission system that consists of several, disconnected networks as shown in Figure 3, as well as the costs of connecting them in the future. There are non-academic works that do use spatially and temporally resolved supply and demand data and consider intra- and interisland power transmission, but only for sub-national cases [27,30,38,39] or at a low spatial resolution [29].

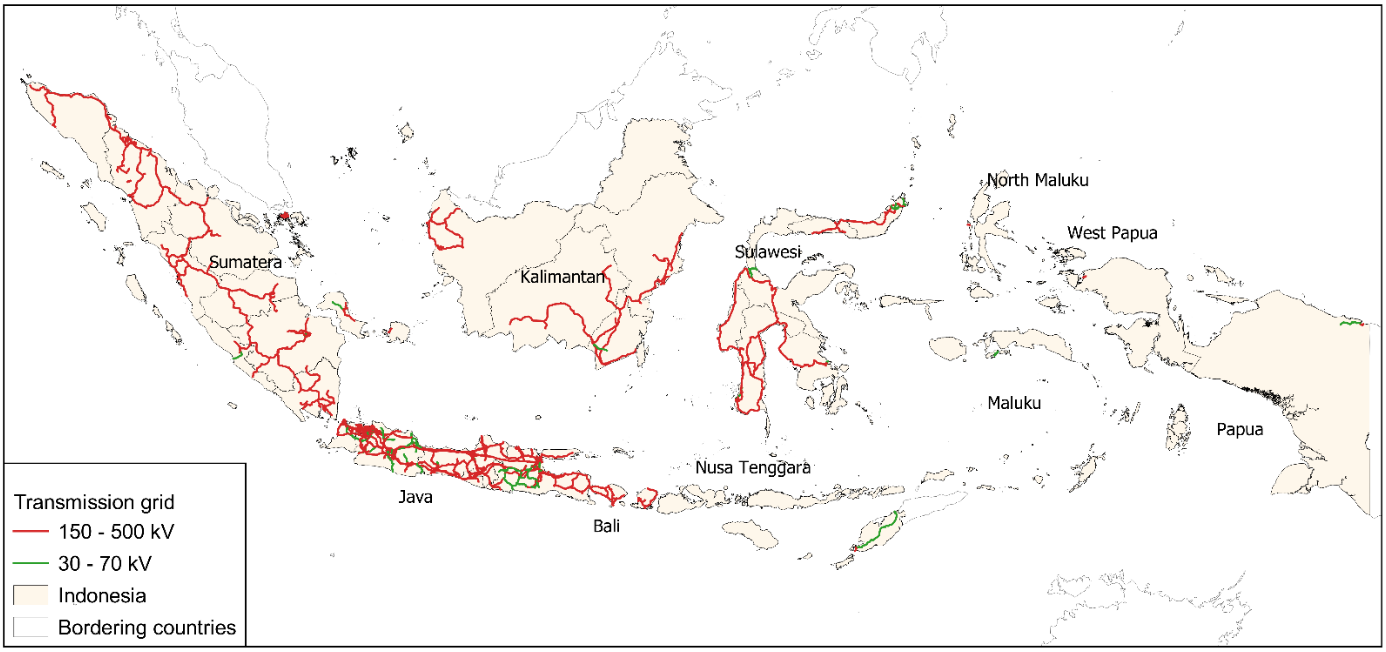

Figure 3. Indonesia's power transmission networks in 2020 [40].

Furthermore, many studies only use one set of inputs without exploring alternatives based on the diversity of possible transmission grid configurations and decarbonisation targets, as well as the uncertainty behind inputs like future technology costs, demand projections, and productivity of variable RET. Exploring these diverse options is important as research on 100% RET electricity systems in Indonesia is scarce [28,41], with most work referring to past official plans, like RUEN [36] and the nationally determined contributions for the Paris Agreement [42,43].

Lastly, all existing energy system modelling work on Indonesia uses proprietary software and data, which makes them less transparent and reproducible.

These limitations considered, this dissertation generates technical and economic RET potential maps for Indonesia at a high spatial and temporal resolution. The set of analysed RET includes a variety of technologies, including low-wind-speed offshore wind and OTEC. These potentials are then fed into a spatially and temporally resolved, state-of-the-art energy system model that reflects Indonesia's transmission network and ranges of possible cost assumptions and demand projections, amongst others. All RET potential maps as well as the code, input, and output data of the energy system model are publicly available to allow for the results' reproduction and further refinement. While the RET mapping process is the same for all studied technologies, we incorporate further technology-specific analyses to enhance this dissertation's scientific contributions and novelty. For example, we assess the impact of site selection flexibility on onshore wind farms, which can be integrated into existing land uses more easily than other RET like ground-mounted PV.

The aim of this research is providing a more transparent and detailed inventory of available RET potentials in Indonesia and contributing to the scientific foundation for Indonesia's capacity planners to decarbonise the electricity system cost-effectively.

5. Research questions

The main research question that drives this dissertation is formulated as:

"What is the technical and economic potential of variable RET for power generation in Indonesia and how could RET contribute to a fully decarbonised power system?"

And is broken down into the following sub questions:

1. *What is the current understanding of renewable energy potentials in Indonesia in academic and non-academic literature and how much present and future demand could they cover?*
2. *What is the technical and economic potential of variable RET in Indonesia considering spatiotemporal resource availability?*
3. *What are Indonesia's options for full power system decarbonisation considering different network configurations, cost assumptions, demand projections, as well as availability and productivity of variable RET?*

6. Overview of methodology and scope

To answer the research questions, this dissertation deploys the research flow depicted in Figure 4. There, we also show the technology-specific further analyses to make our research globally relevant beyond Indonesia. The following sub sections provide an overview of the methods used for RET potential mapping and energy system optimisation modelling.

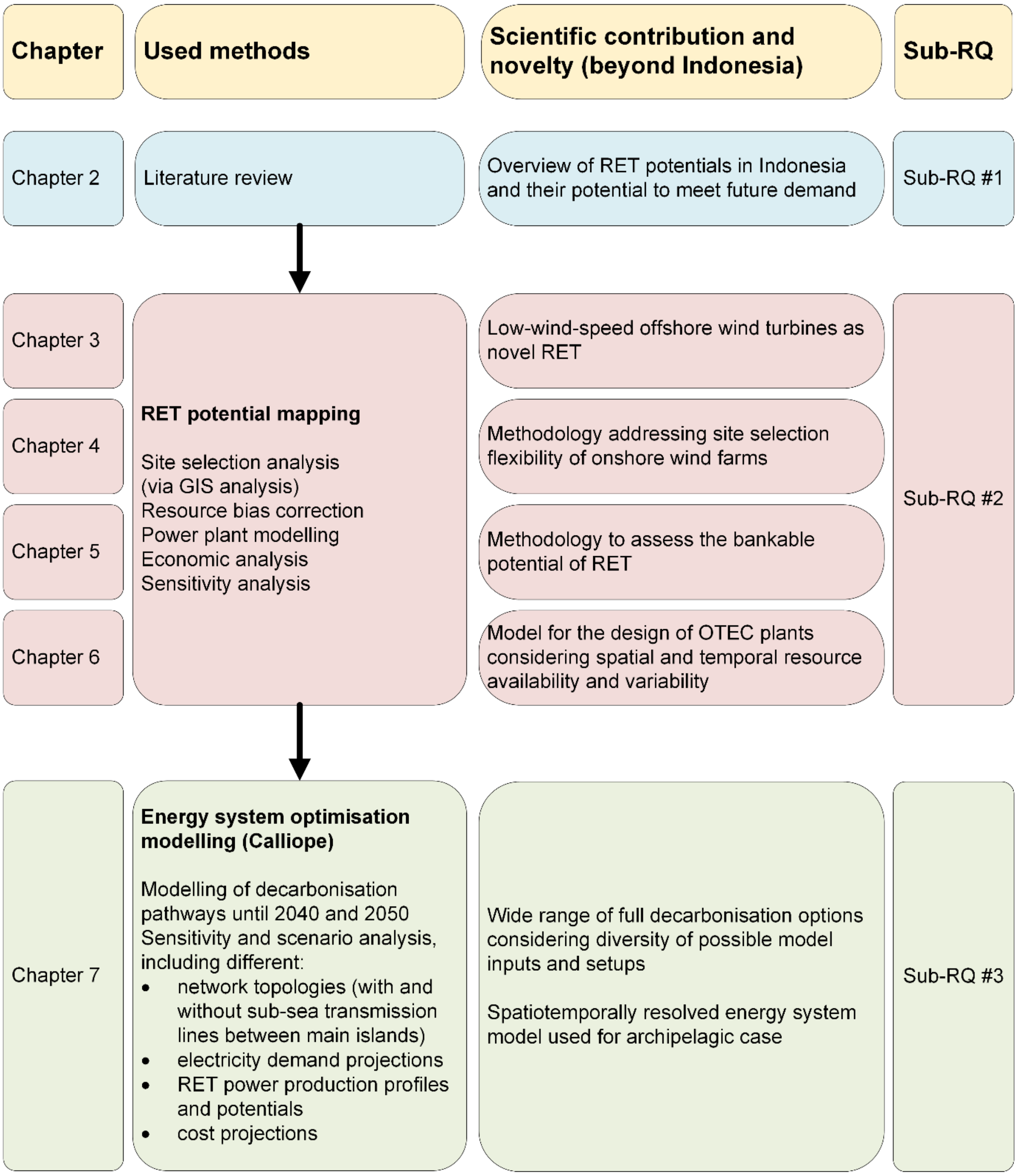

Figure 4. Research flow diagram showing used methods, the scientific contribution and novelty of each chapter, and how the chapters of this dissertation are linked to the sub research questions. RET: Renewable Energy Technology, OTEC: Ocean Thermal Energy Conversion, RQ: Research question, GIS: Geographic Information System.

6.1. RET potential mapping

Figure 5 gives a general overview of the RET potential mapping process deployed in this dissertation, demonstrated for ground-mounted, utility-scale solar PV. We start with the entire land area in panel (a). Using *Geographic Information System (GIS)* software, we then remove any unsuitable areas, e.g., nature conservation zones and water bodies. The remaining, suitable areas are shown in panel (b). Next, we determine the resource availability at these sites using resource maps, like *Global Solar Atlas (GSA)* [44]. The GSA has a fine resolution of 250 m × 250 m, and all pixels inside the PV sites are sampled to obtain the average annual power production per site in panel (c).

The downside of resource maps like GSA is that they are not temporally resolved, meaning that they only show the average annual power production. They do not show the intraday and seasonal fluctuations, which is important when modelling the power production of variable RET. There are meteorological datasets that contain data like solar irradiation in hourly timesteps for many decades, e.g., ERA5 *reanalysis*. These datasets, however, have a low spatial resolution (30 km × 30 km for ERA5) and do not capture the detailed local orography [45]. Hence, GSA and reanalysis are complimentary and would, if coupled, enable the modelling of renewable power production at high spatial and temporal resolution. This coupling is achieved via a method called *bias correction*, which we explain below.

As shown in panel (d), we first generate the centroids of the PV sites containing the GSA power production. Then, we add the ERA5 datapoints to the map and determine the closest ERA5 point for each centroid. Next, the GSA power production of the centroids are compared to the power production of the ERA5 datapoint closest to them. The latter is calculated using a PV system model with ERA5 reanalysis as input. From the comparison, we obtain a time-invariant scaling factor for each centroid, called *bias correction factor*. For example, if the GSA power production at a site is 1,455 kWh/kW$_p$/year and the aggregated annual power production at the closest ERA5 point is 1,619 kWh/kW$_p$/year, then each hourly value of the ERA5 power production profile is multiplied by a bias correction factor of 1,455/1,619 = 0.9, as shown in panel (e) and (f). Applying this correction factor, the power production profiles from ERA5 match the site-specific GSA values on an annual basis.

The bias-corrected profiles are used to calculate the RET's technical and economic potential. We define the technical potential as the aggregated annual electricity production of all technically feasible RET plants in Indonesia. On the socio-economic level, the economic potential is the part of the technical potential with *Levelised Cost of Electricity (LCOE)* equal to or lower than the local tariff. The LCOE is the average tariff necessary to break even with all costs accrued over a plant's lifetime [12]. For ground-mounted, utility-scale solar PV, we also calculate the bankable potential, which we define as the part of the technical potential that secures funding and is sufficiently profitable from a private investor's perspective.

Table 1 displays how we applied the methodology above per technology. For the RET potential mapping part of this dissertation, we only focussed on variable RET, thus excluding dispatchable RET, like biomass, reservoir hydro, and geothermal. Moreover, we did not map RET for which it was computationally not possible to generate power production profiles for the entire country, e.g., wave and tidal power as well as rooftop PV. Finally, concentrated solar power was omitted in the second half of the PhD project due to time constraints. For the energy system modelling part of the dissertation, we did include biomass, reservoir hydro, and geothermal, but not the other abovementioned RET, which we justify in Box IV in chapter 7.

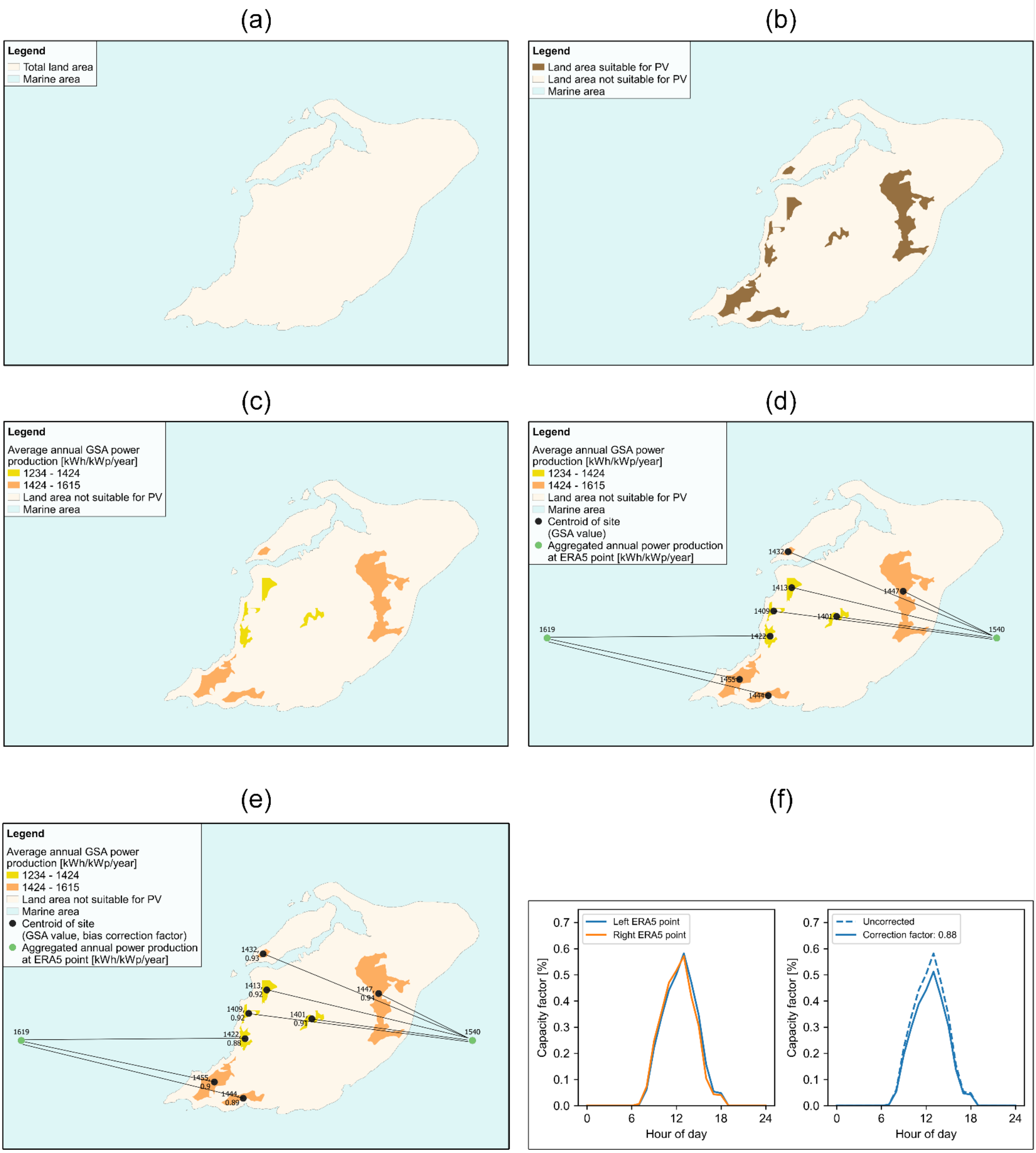

Figure 5. Steps of the general RET potential mapping methodology used in this dissertation, starting with panel (a) and ending with panel (e), demonstrated for solar PV on Boano Island, West Seram, Maluku, Indonesia. The left graph of panel (f) visualises the power production profiles of the two ERA5 points shown in panels (d) and (e), and the right graph of panel (f) shows how the effect of the bias correction factor for the left ERA5 datapoint in panels (d) and (e).

Table 1. Variable RET mapped in this dissertation. For further information, see the respective chapters listed in the table.

Technology	High-spatial-resolution dataset	Reanalysis data	Appearance in dissertation
Ground-mounted, utility-scale solar PV	Global Solar Atlas [44]	*ERA5* [46] • Surface solar radiation downwards • Eastward wind speed at 10m • Northward wind speed at 10m • Surface Pressure • Ambient temperature 2m above ground • Dew point temperature 2m above ground	Chapter 5 and 7
Onshore wind	Global Wind Atlas [47]	*ERA5* [46] • Eastward wind speed at 100m • Northward wind speed at 100m	Chapter 4 and 7
Offshore wind	Global Wind Atlas [47]	*ERA5* [46] • Eastward wind speed at 100m • Northward wind speed at 100m	Chapter 3 and 7
OTEC	Not available at relevant water depths	*Global Ocean Physics Reanalysis* [48] • Seawater potential temperature at 21.6m, 644m, 763m, 902m, and 1,062m water depth	Chapter 6 and 7
Hydropower	Hoes et al. [49]	*ERA5* [46] • Surface runoff	Chapter 7 (see Appendix P for methodological details)

6.2. Energy system optimisation modelling

In this dissertation, we feed the previously mapped RET potentials into the open-source energy system optimisation model Calliope [23] to model the full decarbonisation of Indonesia's electricity system. Calliope uses nodes and interconnections between them to establish model regions and their production, consumption, storage, and exchange of energy carriers. In our model, each node represents one of Indonesia's provinces (34 at the time of the analysis). The interconnections are based on official plans to expand Indonesia's power grid on and across its main islands. Calliope determines the necessary generation, storage, and transmission capacities to meet demand and optimises for total system cost. For decarbonisation, we investigate the target years 2040 and 2050, and linearly retire the fossil generation capacity from 2020 to reach these targets. For example, if the target year is 2040, the fossil capacity in 2030 is half of the 2020 capacity, and zero in 2040.

Given the variety of possible system designs and the uncertainty of inputs like costs and demand, we perform a scenario and sensitivity analysis. As a result, we do not report on *one*, but a set of optimal future system configurations reflecting the impact of using different power transmission networks, demand projections, cost assumptions, and RET potentials, amongst others. We only focus on electricity and omit other energy carriers like heat and hydrogen, which limits the model's complexity and runtime, but disregards sector-coupled solutions for Indonesia's entire energy system.

7. Context of PhD project

This research is being performed as part of the joint research project entitled “Regional Development Planning and Ideal Lifestyle of Future Indonesia - By Utilizing Advance Green Energy Technology and Trans/Inter-disciplinary Approaches” between Delft University of Technology (TU Delft), The Netherlands, and Institut Teknologi Bandung (ITB), Indonesia. Within the Cooperation Indonesia – The Netherlands programme, the project is funded under the Merian Fund by the Dutch Research Council (NWO) and by the Indonesian Ministry of Research and Technology and National Research and Innovation Agency (RISTEK-BRIN) for 2 years and by the Indonesian Ministry of Education, Culture, Research, and Technology (Kemendikbudristek) for 1 year.

On the ITB side, there are nine work packages on diverse topics for Kalimantan and Bali, including land-use analysis, biomass and hydropower potentials, as well as stakeholder engagement, policy impact analysis, and business incubation. On the TU Delft side, there are two work packages, one of which dealing with the co-creation of renewable energy pathways for Bali and Kalimantan. The other work package, i.e., this dissertation, spans over the entire country of Indonesia and addresses renewable energy technology assessment and system integration analysis via energy system optimisation modelling.

8. Dissertation outline

This dissertation is structured as follows.

Chapter 2: Review of renewable energy potentials and their implementation in Indonesia

This chapter reviews academic and non-academic literature on the theoretical, technical, and economic potential of RET in Indonesia. We assess whether and to which extent these potentials meet present and future demand, and how a fully renewable electricity system could be shaped by them. For solar PV and offshore wind, we further investigate how much land and marine area would be occupied by them. The knowledge gaps detected there establish the scientific foundation of the dissertation and chapters thereafter.

Chapter 3: The technical and economic potential of low-wind-speed offshore wind

Currently, the global offshore wind industry develops towards increasingly large turbines for regions with high wind speeds. In contrast, turbines designed for low to medium wind speeds are only available on the market for onshore application. Low-wind-speed regions like Indonesia therefore cannot benefit from the abovementioned offshore developments. In this chapter, we investigate the technical and economic potential of low-wind-speed offshore wind in Indonesia. For that, we assume that currently available low-wind-speed onshore wind turbines are modified for offshore use.

Chapter 4: The technical and economic potential of onshore wind

Unlike other renewables, the land occupied by onshore wind farms can be shared for other uses, e.g., agriculture and forestry. Depending on whether such shared land use is politically desired and socially accepted, the resulting technical and economic potentials can vary significantly. This chapter proposes a methodology for the flexible mapping of onshore wind potentials and shows how the degree of site exclusion impacts the potentials and costs.

Chapter 5: The technical, economic, and bankable potential of ground-mounted, utility-scale solar PV

From chapter 2, it already became clear that the technical potential of ground-mounted, utility-scale solar PV is high with relatively low generation cost. However, investments in the technology so far are low and thus pose questions about the PV's bankability that are not yet addressed in contemporary literature. This chapter lays out a methodology to calculate and map the bankable potential of RET using cash flow analysis, Monte Carlo simulation, and geospatial analysis. We apply the model to ground-mounted, utility-scale solar PV in Indonesia and compare the bankable potential to the socio-economic potential.

Chapter 6: The global technical and economic potential of Ocean Thermal Energy Conversion

For RET like PV and wind power, the modelling of spatially and temporally resolved power production profiles is already well-established via PV system and wind farm models. For OTEC, such a model did not exist yet and, instead, analyses in literature have been conducted assuming nominal conditions. However, OTEC would most of the time operate under non-nominal, off-design conditions considering the seasonal variability of ocean thermal energy resources. In this chapter, we present an open-source model that sizes OTEC plants for best economic performance considering the spatial and temporal resource availability and variability.

Chapter 7: Full decarbonisation scenarios for Indonesia's power sector

All inputs and results gained from the previous chapters flow into this chapter, which sketches scenarios for the full decarbonisation of Indonesia's power sector. We use the state-of-the-art energy system optimisation model Calliope to obtain a set of optimal system configurations considering different transmission grid configurations, cost assumptions, and demand projections, amongst others. We discuss by which year full system decarbonisation could be feasible and at what rate existing fossil capacity would need to retire and renewables would need to be scaled up. Besides the diversity of decarbonisation options, we also focus on overarching trends.

Chapter 8: Conclusions, discussion, and recommendations

The final chapter provides overarching conclusions from the research performed for this dissertation. The main and sub research questions are addressed and the research methods as well as design are critically reflected on. Moreover, recommendations for further research are laid out.

2. Review of renewable energy potentials and their implementation in Indonesia

Abstract: Indonesia has an increasing electricity demand that is mostly met with fossil fuels. Although Indonesia plans to ramp up *Renewable Energy Technologies (RET)*, implementation has been slow. This is unfortunate, as the RET potential in Indonesia might be higher than currently assumed given the archipelago's size. However, there is no literature overview of RET potentials in Indonesia and to what extent they can meet current and future electricity demand coverage. This chapter reviews contemporary literature on the potential of nine RET in Indonesia and analyses their impact in terms of area and demand coverage. The study concludes that Indonesia hosts massive amounts of renewable energy resources on both land and sea. The potentials in the academic and industrial literature tend to be considerably larger than the ones from the Indonesian Energy Ministry on which current energy policies are based. Moreover, these potentials could enable a 100% renewables electricity system and meet future demand with limited impact on land availability. Nonetheless, the review showed that the research topic is still under-researched with three detected knowledge gaps, namely the lack of (i) economic RET potentials, (ii) research on the integrated spatial potential mapping of several RET and (iii) empirical data on natural resources. Lastly, this study provides research and policy recommendations to promote RET in Indonesia.

Chapter 2: Review of renewable energy potentials and their implementation in Indonesia

This chapter was originally published as and updated from Langer, J., Quist, J., Blok, K. Review of Renewable Energy Potentials in Indonesia and Their Contribution to a 100% Renewable Electricity System. Energies 2021, 14, 7033. https://doi.org/10.3390/en14217033.

For this dissertation, we revised the published paper to address methodological shortcomings and errors that were discovered after the paper's publication. These corrections pertain to the definition of the potentials, their comparison to current and future electricity demand, as well as the labelling of geothermal potentials. These revisions do not affect the key findings of the paper. For a detailed description of the revisions, see Appendix A.

Abbreviations

Abbreviation	Meaning
ASELI	Asosiasi Energi Laut Indonesia (Indonesian Ocean Energy Association)
EEZ	Exclusive Economic Zones
ESDM	Kementerian Energi dan Sumber Daya Mineral (Ministery of Energy and Mineral Resources)
IESR	Institute for Essential Services Reform
LCOE	Levelized Cost of Electricity
OTEC	Ocean Thermal Energy Conversion
PLN	Perusahaan Listrik Negara (State Electricity Company)
PV	Photovoltaic
RUEN	Rencana Umum Energi Nasional (National Energy Plan)

1. Introduction

Indonesia is a strongly growing country and could become the world's 4th largest economy by 2050 [50]. This development is reflected by Indonesia's rapidly increasing electricity demand of more than 6% p.a. since 2000 [51,52]. Until now, the archipelago mostly depends on its abundant domestic resources of coal and natural gas to meet this demand [53]. Nevertheless, Indonesia has committed to the energy transition via the national energy plan *(Rencana Umum Energi Nasional—RUEN)* and targets a share of *Renewable Energy Technologies (RET)* in the energy mix of 23% and 31% by 2025 and 2050, respectively [5].

Large hydropower, geothermal and biomass are already substantial parts of Indonesia's electricity mix with 17.3% in 2018 [53]. In contrast, the shares of alternatives like solar *photovoltaics (PV)* and wind power are considerably lower, while ocean energy has not been implemented at all. The reasons for the stagnant development of the latter technologies are manifold, including lack of experience, limited grid flexibility to balance intermittent power production [54–57] as well as opaque and incomplete pricing schemes, investment-repelling regulation and complicated, time-consuming licensing processes [5]. Notwithstanding, the implementation of RET might benefit from a more comprehensive and accurate overview of their potential in Indonesia. With such an overview, it would be possible to assess how much current and future electricity demand could be covered with RET. Moreover, energy scenarios like a 100% renewable electricity system and its requirements like land area could be deduced. With these insights, it would be possible to evaluate whether current RET implementation goals are in line with the potentials and whether adjustments are needed. To our knowledge, such an overview does not exist yet in literature.

This chapter addresses this knowledge gap by reviewing existing academic, industrial, and governmental literature on renewable energy potentials in Indonesia. The focus is set on the provincial and national level and distinctions are made between the theoretical, technical, and economic potential as shown in Table 2. Moreover, this study critically analyses what is necessary to activate these potentials in terms of required land areas and indicates the impact of the potentials on current and future electricity demand. Light is also shed on how implementation proceeded compared to the plans expressed in the RUEN.

The scientific contribution of this chapter is not only to provide an overview of existing literature on RET potentials in Indonesia but also to critically put them into perspective in terms of impact and realisation requirements. Moreover, this study aims to raise awareness to researchers, policymakers, and investors about Indonesia as a country that not only hosts a diverse set of renewable resources but also has a large and rising energy demand. By discovering current knowledge gaps in the literature, future research directed towards these gaps might contribute to knowledge on both Indonesia's energy transition and climate change mitigation with benefits beyond national borders. Therefore, the results also have significant policy relevance.

The chapter is organised as follows. Section 2 elaborates on the methods to search and select literature as well as defining the boundaries of the review. Section 3 presents the results of the literature review, followed by a critical discussion in section 4. The chapter ends with conclusions and recommendations in sections 5 and 6.

2. Methods and materials

2.1. Literature collection and review

An overview of the literature review is depicted in Figure 6. Backwards snowballing was used to trace primary literature with a maximum of two iteration cycles. Regarding language and grammar, studies were left out if the main message of the reviewed publication could not be unequivocally reconstructed. In case a study was filtered out on abstract scan, it was still fully read if its content was helpful for the storyline of this study. Thus, the elaborations in the following sections are not only based on the 38 extracted studies in Figure 6. Out of the 38 reviewed studies, four come from the Ministry of Energy and Natural Resources *(Kementerian Energi dan Sumber Daya Mineral—ESDM),* five from industrial sources and 29 from academic literature. 22 publications focus on the national, six on the global level, and five studies each on the provincial and inter-provincial, regional level. Regarding the technologies, seven studies each were about a set of RET and solar PV, six studies were about biomass, five studies each were about wave energy and tidal current and two studies each were about hydropower, *Ocean Thermal Energy Conversion (OTEC)*, offshore wind and geothermal. 34 studies are in English, four in Indonesian (Bahasa Indonesia).

Figure 6 shows that 182 studies were filtered out due to being secondary literature or a too regional scope. This study aims to draw insights from potential studies that can be scaled to the national or at least provincial level. Local case studies might not be scalable to such an extent, especially for locally sensitive technologies like wind power, which is why they are excluded here. Nonetheless, it is acknowledged that localised RET research is highly important, as decentralised RET can be a gateway for community empowerment and local socio-economic development [58,59].

2.2. Reviewed technologies and definition of potentials

The nine reviewed technologies comprise geothermal, large and small hydropower, biomass, solar PV, wind power as well as tidal power, wave energy and OTEC. Unless stated otherwise, this literature review focuses on RET for electricity production, while other applications such as heat, cooling and transportation are excluded. Moreover, the state of the art of individual technologies and power plants is not reviewed as such works already exist as pointed out in the respective sub-sections. The review of energy statistics is limited to the context of RET since general statistics for the whole Indonesian energy system were covered recently [36,54,57,60].

In literature, there are various definitions and classifications of potentials as shown in Table 2. One commonality of these studies is the subdivision into *theoretical, technical*, and *economic* potential, which we will adopt for this chapter. We define the theoretical potential as the energy content of the resource across the studied region. The technical potential is the part of the theoretical potential that can be deployed given technical (e.g. efficiency and technical limitations) and non-technical (e.g. nature conservation zones and land occupation) constraints. The economic potential is the part of the technical potential which is economically viable, e.g. in comparison against other renewables or benchmark prices. We do not consider the market potential as no literature on the matter was found for Indonesia.

The potentials found in literature are shown in their original physical units and converted to GW_e to make them comparable. For units of energy, the potential is converted to GW_e using average generation efficiencies (electricity output divided by primary energy input) and capacity factors (generated electricity divided by installed capacity and 8,760 h/year) of Indonesian power plants based on the statistics provided by ESDM [51].

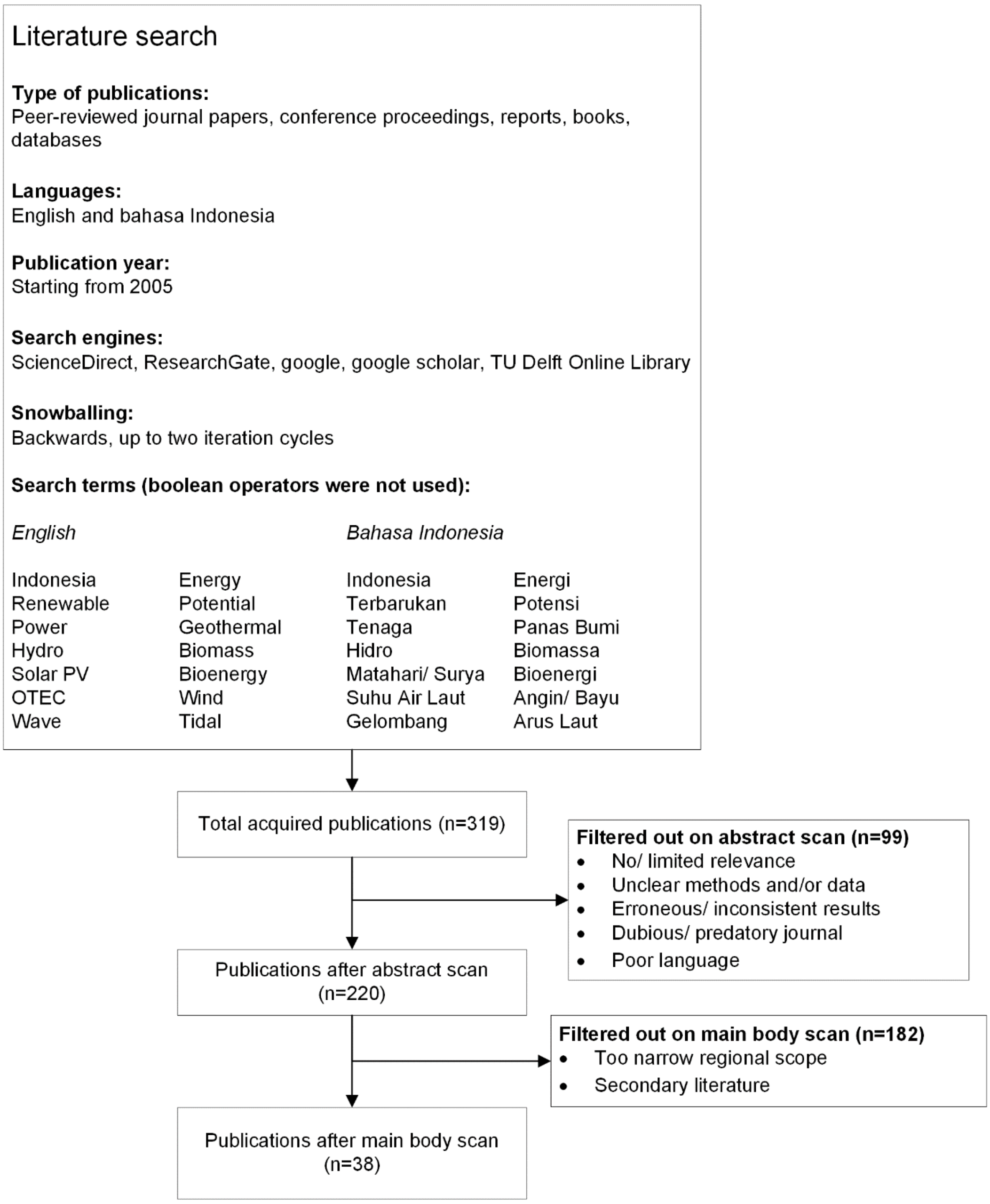

Figure 6. Methods used for the systematic literature review on RET potentials in Indonesia.

2.3. Comparison to electricity demand and the national development plan

To put the reviewed potentials into context in terms of their possible role in Indonesia's electricity system, we compare them to current and future demand in terms of required electricity generation. In 2018, national electricity generation was 284 TWh to meet demand [53], which we use as a benchmark for current demand coverage. Until 2050, demand is projected to rise significantly, although growth estimations can vary across studies between roughly 4% p.a. [28,61,62] and 8% p.a. [30,63]. In this chapter, we take the average 2050 generation of 2,190 TWh from DEN's [24] scenarios as a benchmark for future demand coverage. Moreover, we compare the current implementation of renewables to the development plans laid out in Indonesia's national energy general plan (*Rencana Umum Energi Nasional – RUEN)*.

Table 2. Different definitions of potentials encountered in literature. The definitions by ESDM were translated from Bahasa Indonesia to English.

	Blok & Nieuwlaar [12]	**Hoogwijk** [64]	**Lopez et al.** [11]	**ESDM** [65]
Theoretical/ resource potential	Available natural energy flows taking only physical limits into account	Theoretical upper limit of primary energy across the total earth surface	Energy content of resource given physical constraints	Potential based on field data via a modelling system
Geographical potential	-	The theoretical potential across land area of studied region	-	-
Technical potential	Contribution made by technologies available in future considering practical constraints	Part of the geographical potential minus losses from conversion to secondary energy carriers	Part of theoretical potential given system, topographic, and land-use constraints	Identified potential that can be implemented at a certain location
Practical potential	-	-	-	Identified potential that can be implemented at a certain location based on long-term data
Acceptable potential	-	-	-	Potential that considers demand, infrastructure, and communal approval
Economic potential	Part of the technical potential that is economically attractive from a socio-economic perspective	Part of the technical potential that can be realised at profitable levels	Part of the technical potential that is economically attractive given projected technology and fuel costs	Potential that can be actually utilised
Profitable potential	Part of the technical potential that is economically attractive from a private investors	-	-	-
(Policy-enhanced) Market/ implementation potential	Part of the technical potential that is likely to be implemented given (policy-enhanced) economic and non-economic barriers and stimuli	Maximum amount of economic potential that can be implemented within a certain timeframe given institutional constraints and incentives	Part of economic potential that is likely to be implemented given policies, regulatory limits, investor response and regional competition with other energy technologies	-

3. Results

3.1. RET in Indonesia and Development Plans

In 2018, Indonesia's share of RET in the electricity mix was 17.4% as shown in Figure 7 [53]. The Levelized Cost of Electricity (LCOE) of renewables and their competitiveness against fossil-fuelled generators in Indonesia are shown in Table 3. What the most prominent RET in Indonesia, namely large hydropower, geothermal and biomass, have in common is their non-intermittent power production. In contrast, fluctuating RET like solar PV and wind power are still at an early stage of implementation in Indonesia [51]. But this might change with the government's current capacity development targets. Indonesia plans to ramp up the total installed capacity from 65 GW in 2018 to 443 GW until 2050, 168 GW of which from RET, as shown in Figure 8(a) [5].

Despite the ambition to develop RET in the Indonesian electricity system, the dominance of fossil fuels would not end with the RUEN but get stronger. So far, both fossil and renewable capacity are not implemented as planned in the RUEN as seen in Figure 8(b), at least in absolute terms. In relative terms, fossil capacity was developed at the planned annual rate of roughly 6%, while RET only grew by 5% per year instead of the planned 9%. This suggests that implementation targets might generally be set too high and that the development of fossil capacity proceeds smoother compared to renewable capacity.

The following sub-sections show the results of the literature review on RET potentials in Indonesia and the impact of these potentials on demand coverage and area usage if possible. Furthermore, the current developments and barriers of each technology are discussed as well as their roles in the RUEN. Based on these insights, it might be possible to explain why RET implementation does not progress as planned.

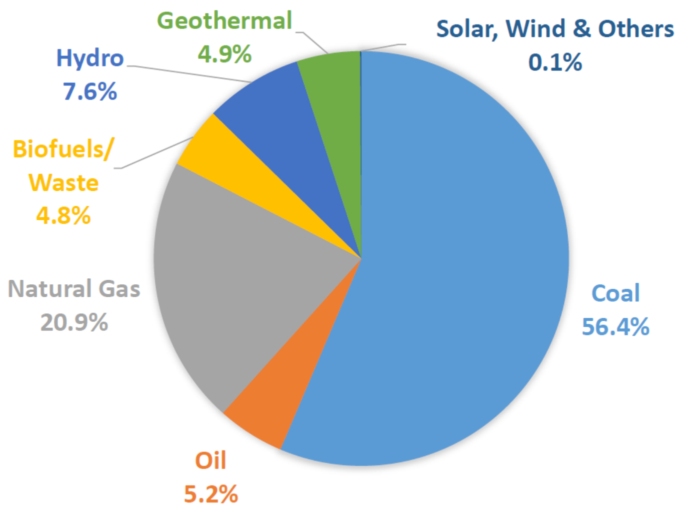

Figure 7. Total electricity supply of Indonesia in 2018 [53].

Table 3. The levelized cost of electricity of renewables and fossil-fuelled generators in Indonesia. Values for OTEC based on [19]*, values for all other technologies based on* [66]*.*

Technology	Levelized Cost of Electricity [US¢/kWh]
Open-Cycle Gas Turbine	9.2–12.94
Combined-Cycle Gas Turbine	6.69–8.93
Coal Mine Mouth	5.01–7.31
Coal Sub Critical	6.11–8.41
Coal Super Critical	5.77–8.05
Coal Ultra Super Critical	5.83–8.38
Onshore Wind	7.39–16.1
Utility Scale Solar	5.84–10.28
Geothermal	4.56–8.7
Biomass	4.68–11.4
Ocean Thermal Energy Conversion (Full-scale plant after 30 years of modelled upscaling)	6.2–16.8

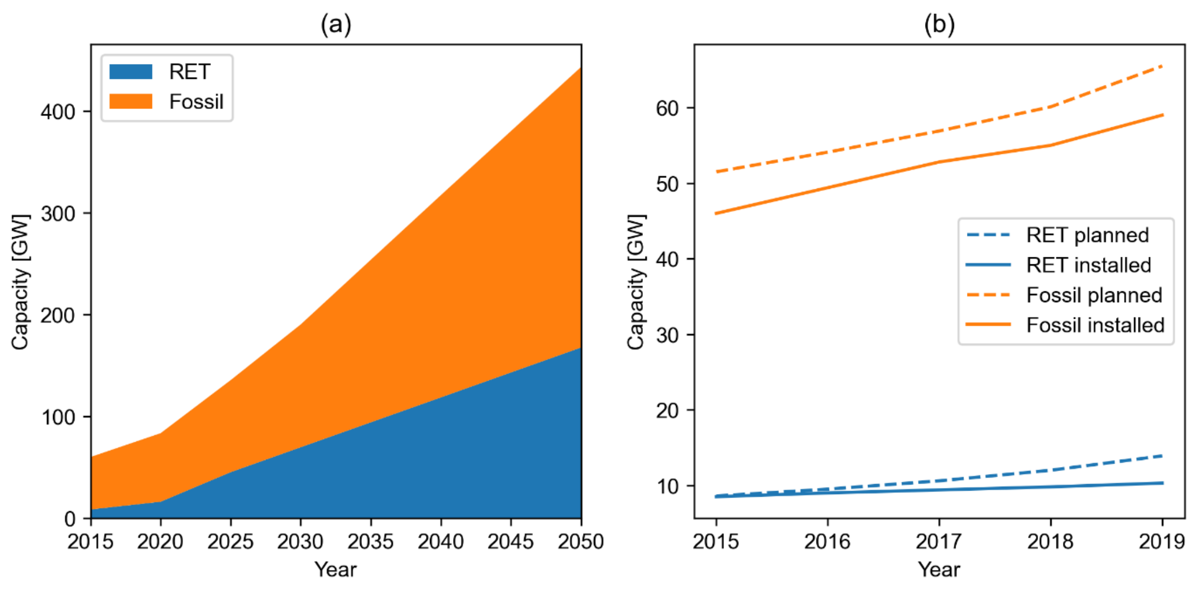

Figure 8. (a) Planned installed capacity of renewable and fossil-fuel-based generation capacity based on RUEN [5] *and (b) installed vs. planned capacity of fossil and RET until 2019* [5,51]*.*

3.2. Geothermal

Geothermal power plants produce electricity by extracting the heat generated and stored within the Earth at depths of around 1 km and below. According to current estimates, Indonesia hosts around 40% of global geothermal resources due to its location on the ring of fire, an area known for seismic and volcanic activity [67,68]. As of 2019, Indonesia deployed 2.1 GW_e or 9% of estimated geothermal resources which produced 14.1 TWh_e [51]. With such a capacity, the country ranks second in global geothermal implementation behind the USA [69].

Estimates on geothermal potentials in Indonesia mainly come from the Geology Agency of ESDM. In contrast to other RET, geothermal potentials are clustered in two categories, namely resources and reserves. Resources are rough estimations of geothermal heat, which might be exploitable if technical and economic prerequisites are met. Reserves on the other hand only include technically and economically recoverable heat based on geoscience survey tools and empirical data like reservoir temperature and size [70]. The Geology Agency aggregates resources and reserves to get a total [51]. Resources can become reserves if they can be extracted economically and vice versa, reserves can become resources again if detrimental economic developments render their extraction unprofitable.

In 2019, geothermal resources and reserves were 9.3 GW_e and 14.6 GW_e [51], respectively. Outside ESDM's work, only one academic study was found that estimated Indonesia's geothermal potential. However, that study did not calculate potentials but proposed a new accounting methodology based on ESDM's values [70]. Additionally, recent literature comprises literature reviews of the geothermal industry in Indonesia [67,68,71,72]. From the industrial side, Royal Dutch Shell [35] indicates technical resources of 1,009 PJ_e per year or 42 GW_e if a capacity factor of 76% is assumed [51]. With such resources, Indonesia's electricity demand in 2018 and 2050 could be covered to 98.5% and 13%, respectively.

Until 2050, an installed geothermal capacity of 17.5 GW_e is planned, which is 4% of the total planned RET capacity [5]. For an additional capacity of 15.4 GW_e, more than 300 new plants would have to be built with an average capacity of 50 MW_e [51]. This exceeds the current reserves of 14.6 GW_e and implies that 2.9 GW_e of current resources must become reserves by 2050. To which extent this is possible depends on economic developments and technical availability, as not all thermal resources are suitable for electricity generation [70]. As of now, the installed capacity in 2019 is 15% lower than projected in the RUEN [51]. Current challenges include complications in obtaining land permits, inadequate electricity tariffs, opposition from local communities, limited data availability and long average lead times of 7–8 years [73].

3.2. Hydropower

Hydropower plants convert the kinetic and potential energy of water into electricity. Depending on the system size, there is large and small hydropower. Although an accepted consensus of 10 MW has emerged as an upper limit for small hydropower, there is no formal definition, leading to regionally variable thresholds [74]. Some works aggregate the potential of both technologies, including Hoes et al. [49] calculating a theoretical potential of 241 GW and Royal Dutch Shell [35] with a technical potential of 205 PJ per year or 15 GW, if a capacity factor of 43% is assumed [51]. In the following, the two technologies are reviewed separately.

3.2.1. Large hydropower

ESDM currently estimates a theoretical large hydropower potential of 75 GW [75,76], a value obtained in 1983 [77]. From this potential, 30% and 29% are situated in Papua and Kalimantan, respectively [65]. The only reviewed industrial study estimates a technical potential of 26 GW and includes restrictions like protected areas, tourism zones, reservoir size and resettlement of residents [78]. In 2019, roughly 5.6 GW or 7.5% of the theoretical potential was installed resulting in an electricity production of around 21 TWh. Malaysian hydropower is the only type of electricity that is imported to Indonesia. Including 1.7 TWh of these imports, large hydropower's contribution to the total electricity supply was 7.7% in 2019 [51].

Large hydropower will be an integral part of the Indonesian energy transition according to the RUEN. Until 2050, an additional capacity of 32.5 GW is planned, which is higher than the technical and technical potentials mentioned above. With a resulting capacity of 38 GW in 2050, large hydropower would form 8.6% of total installed capacity, making it the second largest renewable generator in Indonesia in terms of capacity after solar PV [5]. Moreover, 38 GW of large hydropower could cover 50% and 7% of Indonesia's electricity demand in 2018 and 2050, respectively. In 2019, implementation exceeded plans by 2% [51].

3.2.2. Small hydropower

Currently, ESDM estimates a theoretical small hydropower potential of around 19.4 GW [65,79]. The highest share of that potential is in East and Central Kalimantan with 18% and 17%, respectively [76]. In 2019, the installed capacity was around 418 MW or 2% of the theoretical potential [51]. In academic literature, small hydropower enjoys more attention than its large counterpart with individual case studies [80–83], a review [84] and a climate change impact study [85].

The rapid upscaling of small hydropower is endorsed in Indonesia due to low costs, local expertise and reliable power production, amongst others [86]. An installed capacity of 7 GW until 2050 is targeted in the RUEN, most of which are in Sumatera, Kalimantan, Java and East Nusa Tenggara [5]. With 7 GW of small hydropower, 9% and 1% of Indonesia's electricity demand in 2018 and 2050 could be covered, respectively. However, implementation lagged by roughly 44% in 2019 [51]. Small hydropower is considered key for rural electrification and community empowerment, while reported barriers include lack of foreign investment, access to finance, as well as limited infrastructure [73].

3.3. Biomass

In the field of energy, biomass encompasses all renewable plant- and animal-based materials for power and heat production. Figure 9 summarises the different types of biomass available in Indonesia and the options for power generation.

The potential of biomass in Indonesia is studied widely by both governmental and academic research. Table 4 shows current literature on biomass potentials in both their original physical units as well as in terms of thermal energy and electrical capacity. ESDM estimated the potential of biofuels, residues from industrial agriculture and biogas for power generation. Elaborations on the methods and assumptions regarding the conversion from thermal to electrical energy could not be found. Currently, ESDM estimates a theoretical biomass potential of 32.7 GW_e [79], with most of the resources being located in Sumatera, the Java-Madura-Bali region and Kalimantan with roughly 48%, 28% and 16%, respectively. Palm oil, as well as rice husk, take the largest shares of the potential with 39% and 30%, respectively [65]. Out of the 32.7 GW_e, municipal waste and biogas from manure comprise potentials of 2.1 GW_e and 0.5 GW_e, respectively [65,75].

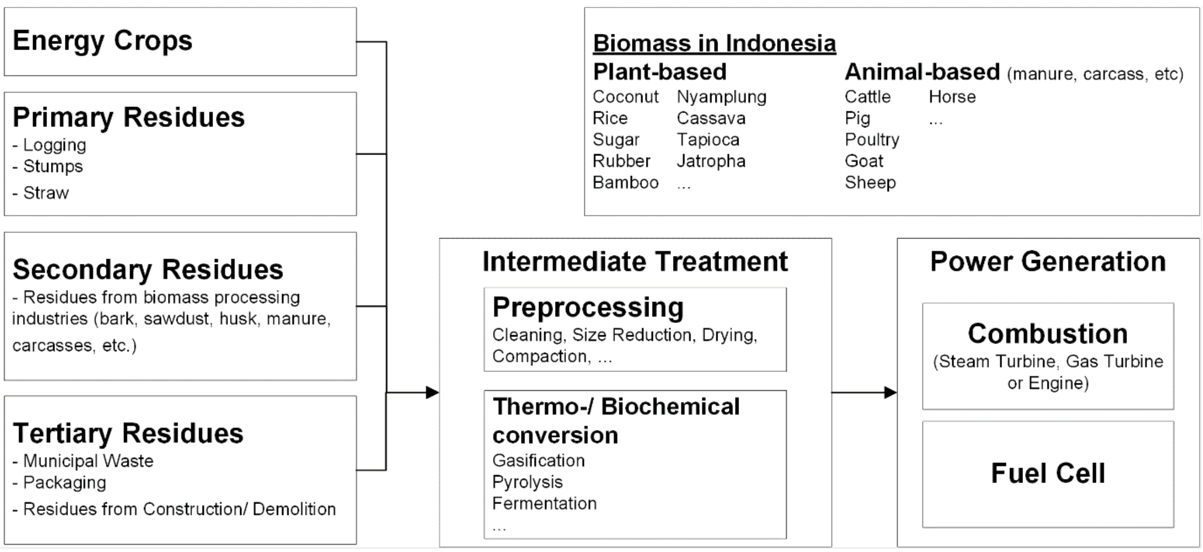

Figure 9. Biomass in Indonesia and options for power production (based on Refs. [87–92]*).*

In academic literature, national theoretical and technical potentials were assessed for solid biomass [88,90,93], biogas [89,94] and bio-methanol for fuel cells [87]. A critical aspect of the sustainability of biomass is its origin. As mentioned above, biomass for energy conversion is primarily produced in palm oil plantations which often renders the local environment a degraded wasteland [95]. Therefore, an increased use of unsustainable biomass for electricity generation might exacerbate deforestation and undermine efforts to make Indonesia's energy system more environmentally friendly. One way to establish sustainable biomass supply chains is the renewed use of degraded land to cultivate plants like bamboo and nyamplung with additional benefits like soil recovery and non-interference with food production [90,93,96]. From a bottom-up perspective, challenges with this option are uncertain land tenure and local ownership as well conflicting interests between investors and local communities [97]. Although potentials in literature can vary considerably, solid biomass potentials tend to be the highest for energy crops, amongst others cultivated on degraded land. They could theoretically cover up to 28% of Indonesia's final energy demand and 30% of electricity demand in 2050. Compared to energy crops, the potential of biomass residues is lower, which is in line with the findings of ESDM.

Recently, the use of biomass for power generation was increased significantly from 0.3% of total generation in 2017 [98] to 4.8% in 2018 [53]. Parts of that share come from the co-firing of biomass in coal plants, which is perceived as one of the cheaper options to promote the energy transition [91]. First tests have already been conducted by ESDM with positive results [99]. However, its feasibility for small-scale, rural application still needs to be addressed [97]. Moreover, there might be lock-in effects for coal-based power generation, as current co-firing plants are designed for a biomass rate of only 10–15% [100]. In the RUEN, a ramp-up to 26 GW until 2050 is projected, which would encompass 15.5% of the total planned renewable capacity [5]. As of 2019, implementation lags by 15% [51] due to barriers like insufficient tariffs, the resistance of local communities as well as lack of stakeholder coordination [73].

Table 4. Biomass potentials in Indonesia. (Co-)firing in steam plants with efficiency and capacity factor of 34.0% and 74.8% respectively. ** Combustion in gas plants with efficiency and capacity factor of 38.4% and 18.8%, respectively* [51,53]. **** Density and heat value of methanol 792 kg/m3 and 22.7 MJ/kg, respectively.*

Ref.	Type of Biomass	Origin of Biomass	Potential			
			Type of Potential	Original Unit(s)	Thermal Energy [PJ_{th}]	Capacity [GW_e]
Solid Biomass						
[65,75]	Primary & Secondary	Agriculture	Theoretical	30.1 GW_e	2,088*	30.1
[88]	Primary & Secondary	Industrial forestry	Technical	132.2 PJ_{th}	132.2	1.9*
[90]	Energy Crops	Degraded land	Theoretical	1,105 PJ_{th}	1,105	15.9*
[93]	Energy Crops	Degraded land	Theoretical	5,000–7,000 PJ_{th}	5,000–7,000	71.9–100.7*
[35]	Energy Crops, Primary & Secondary	Industrial forestry and agriculture	Technical	1,225 PJ_{th}	1,225	17.6*
Biogas						
[65,75]	Secondary	Manure	Theoretical	535 MW_e	8.3**	0.5
[89]	Secondary	Livestock farming	Theoretical Technical	9,597.4 Mm^3/year 1.7×10^{10} kWh_e/year	159.4**	10.3**
Waste-to-Energy						
[65,75]	Tertiary	Agriculture	Theoretical	2.1 GW_e	145.7*	2.1
[94]	Tertiary	Households, industry, etc.	Theoretical Technical	2,992 GWh_{th}/year 1,172 GWh_e/year 343 MW_e	10.8	0.3
Bio-Methanol						
[87]	Primary & Secondary	Natural and industrial forestry	Technical	40 – 169*10^9 litre 42–176 GWh_e/year 10–42 GW_e	730–3.040***	10–42

3.4. Solar PV

Solar energy can be converted to electricity in numerous ways, e.g. with PV modules on which this section will focus. ESDM estimates a theoretical solar PV potential of 3,551 GW_p [101] with forest areas and 1,360 GW_p [5,65] without forest areas, respectively. The theoretical potential is then multiplied with a uniform efficiency of 15%, resulting in a technical potential of 533 GW_p [101] with forest areas and 208 GW_p [5,65,76] without forest areas. Although ESDM only mentions forest areas as an exclusion criterion, their solar PV potential map indicates that conservation areas are considered as well [5]. The largest shares of the photovoltaic power potentials are situated in the West and the North of the country, especially in Sumatera with 32% and Kalimantan with 25%, respectively [65].

However, if forest and conservation areas are the only exclusion criteria, the technical potentials are rather small as shown in Table 5. Assuming an installed capacity of 150 W_p/m^2 and using current statistics on total land, forest, water, and conservation areas, the technical solar PV potential would be 99 TW_p if the entire eligible area would be covered with solar panels. Only 0.21% of eligible land area and 0.07% of total land area would be needed for 208 GW_p which seems conservative. For instance, roughly 0.1% of Germany's total land area was already covered with solar PV in 2019 (based on installed capacity of 49 GW_p [102], power production of 150 W/m^2, and total land area of 357,386 km^2). It could be that ESDM used further exclusion criteria, but these were not confirmed by the reviewed material. Nonetheless, solar PV's prospect of becoming Indonesia's key energy technology is apparent even with ESDM's values. Assuming an annual solar electricity production of 1,377 kWh/kW_p [103], the electricity production from 208 GW_p would be enough to cover 101% of Indonesia's electricity demand in 2018 and 13% of the projected demand in 2050.

Table 5. The technical potential of solar PV based on ESDM [5,65,76] *and own estimations for maximum land coverage excluding forest, water, and conservation areas.*

Region	BPS [1]	ESDM	Own Estimation	
	Land area (excl. forest, water, and conservation area) [km²]	**Tech. potential [GW_p]**	**Area coverage for ESDM potentials [%]**	**Tech. potential with land area [GW_p]**
Sumatera	251,603	69	0.070	37,740
Java	96,312	32	0.032	14,447
Bali, East & West Nusa Tenggara	43,870	19	0.019	6,581
Kalimantan	176,921	53	0.053	26,538
Sulawesi	53,422	23	0.023	8,013
Maluku & North Maluku	14,547	5	0.005	2,182
Papua & West Papua	20,991	8	0.008	3,149
Total	**657,666**	**208**	**0.21**	**98,650**

The potentials found in academic and industrial work are much higher than the ones from ESDM and are summarised in Table 6. IESR [14] found a technical potential of 20 TW_p while excluding protected and forest areas, water bodies, wetlands, airports, harbours and areas with slopes higher than 10°. With further exclusion criteria like agricultural and settlement areas, a technical potential of 3.4 TW_p was calculated, which would cover Indonesia's electricity demand in 2018 16 times and the projected demand in 2050 twice. For such a capacity, 3.4% of Indonesia's suitable land area is necessary. Another industrial estimation on technical solar PV potentials comes from the Royal Dutch Shell Database [35] with 6,569 PJ or 1.3 TW_p.

Table 6. Overview of academic and industrial solar PV potential research.

Ref.	Publication type	Regional scope	Potential [GW_p]		
			Theoretical	**Technical**	**Economic**
[14]	Report	National	-	3,400–20,000	-
[35]	Database	National	-	1,300	-
[15]	Journal Paper	On-Grid National	-	27–1,100	0.4
[104]	Journal Paper	Off-Grid National	-	0.8	-
[105]	Book	National	-	73.3–3,200 (on-grid) 0.4–45,900 (off-grid)	-
[32]	Journal Paper	West Kalimantan	-	148	-
[106]	Journal Paper	West Kalimantan	-	2.0	-
[33,107]	Journal Paper	Bali	-	80	-

Solar PV is planned to be the most dominant technology in terms of installed capacity with 45 GW_p in 2050, which would be 10.1% of total and 26.8% of renewable capacity. For this, the roofs of up to 30% of government buildings and up to 25% of developed residential housing should be occupied by solar PV. Another plan is the development of a vertically integrated, domestic PV industry [5]. However, solar PV struggles to gain traction in Indonesia today and implementation trails behind by over 73% [51], as shown in Figure 5(a).

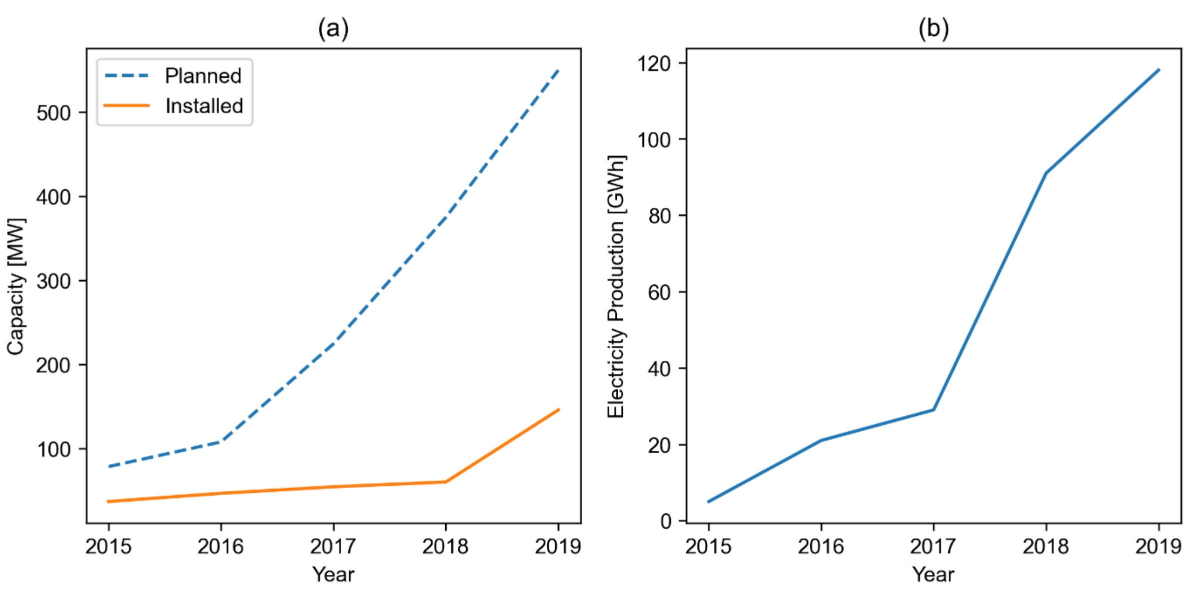

Figure 10. (a) Planned vs. installed solar PV capacity. (b) Electricity production from solar PV [5,51].

A closer look into ESDM's statistics reveals that the problems mostly come from grid-connected systems. Although off-grid PV systems only comprise 28% of the total installed capacity of 146 MW_p in 2019, they produced 54% of the total solar electricity production. Based on Figure 10, an average capacity factor as low as 2% underlines the operational problems of some solar PV systems documented in the literature [55,56]. Then again, statistical errors might also be responsible for the low factor, given that Figure 10(a) and Figure 10(b) are not always aligned. On a positive note, solar PV already contributes to the electrification of rural communities. As part of a government programme, over 360,000 solar-powered lamps have been distributed across Indonesian communities [65,108]. These and other efforts seem to pay off and the recorded performance of the off-grid solar system should be an encouragement to promote even more solar systems in Indonesia both on- and off-grid. To do so, several barriers must be tackled, which for solar PV include complications in land ownership, unattractive tariffs and policy support, lack of local experience [73] as well as active resistance from the state-owned utility company PLN [56].

3.5. Wind power

The kinetic energy of moving air can be converted to electricity using wind turbines. ESDM estimated a theoretical and technical onshore wind potential with and without forest and conservation areas. At locations with average wind speeds above 6 m/s, 1 MW wind turbines were assumed with an area requirement of 1 km^2 per turbine. At locations with wind speeds between 4 and 6 m/s, 100 kW turbines with an area requirement of 0.25 km^2 were assumed [109]. The wind speeds were mapped at heights between 30–50 m at 120 locations [65]. Offshore locations were excluded in ESDM's assessments and the differences between potentials were not elaborated. The theoretical and technical potentials of onshore wind are 113.5 GW and 30.8 GW [109] with and 60.6 GW and 18.1 GW [5,65] without forest and conservation areas. Assuming a capacity factor of 36% [51], the latter technical potential would be enough to cover 22% of Indonesia's electricity demand in 2018 [53] and 3% of the projected demand in 2050 [5,24]. Most of the theoretical potential is in Java and East Nusa Tenggara with 38% and 17%, respectively. More comprehensive wind measurements and analyses are recommended to refine the potential [76]. As with solar PV, ESDM's wind potentials might be too conservative for three reasons. First, it is again not clear whether forest and conservation areas were the only spatial restriction areas on land, given that 18 GW of wind power would merely require 2.7% of Indonesia's total land area. Second, the assumed capacity densities might be too pessimistic, as current practice and studies suggest a density of 7 MW/km^2 [110]. Third, the omission of offshore wind removes a vast and otherwise eligible area for wind power deployment. Although there are good reasons to omit offshore wind in some areas, for example interfering shipping routes and high risk of natural catastrophes, no explanation for the exclusion could be found in ESDM's reports.

Rethinking the exclusion of offshore wind might be worthwhile, as academic and industrial sources suggest a far higher offshore than onshore wind potential. Bosch et al. [34] conducted a global offshore wind analysis and calculated a technical potential of 3.0 TW and 8,318 TWh in Indonesia, using exclusive economic zones, conservation areas, vicinity of marine cables and water depth as exclusion criteria. This potential could cover Indonesia's electricity demand in 2018 29 times and the projected demand in 2050 four times. To implement such a capacity, roughly 7% of the 6,020,917 km^2 [111] of the total available sea area of Indonesia would be required (assuming capacity density of 7 MW/km^2). In the database of Royal Dutch Shell [35], the technical on- and offshore wind resources are 69 and 14,174 PJ, or 6 and 1,248 GW with a capacity factor of 36% [51], respectively. In the underlying study of the database [110], floating wind turbines were included up to a water depth of 1,000 m. This opens up a new dimension of potential as mounted offshore turbines cannot be implemented at such depths today.

Gernaat et al. [16] estimate a technical offshore potential of 53 EJ, which translates to a capacity of 4,668 GW or 260 times ESDM's potential. It is unclear why this potential is so high, given that the water depth and distance to shore were restricted to 80 m and 139 km, respectively, while the other two studies [34,35] above include depths of 1,000 m for floating wind turbines and a distance to shore of more than 200 km. There might be differences in input data and limited accuracy due to low-resolution data. In contrast to Deng et al. [110] and Bosch et al. [34], who use wind speed data with a resolution of 19 km and 5 km, respectively, Gernaat et al. [16] do not mention the data resolution, so their estimation could not be checked. No other academic study on the national or provincial potential of wind power was found to validate these numbers. Instead, both international [112–114] and Indonesian [115–117] research tends to focus more on local case studies. Even if Gernaat et al.'s [16] potential would be technically possible, the practical hurdles would be high given that 11% of Indonesia's available sea area would be needed for such a capacity.

Until 2050, 28 GW of wind power are planned to be installed, but Figure 11(a) shows that implementation lagged by roughly 60% in 2019, notwithstanding a significant growth of electricity production from wind power since 2017 as Figure 11(b) illustrates [5]. In 2019, 154 MW or 0.25% of ESDM's technical potential were tapped. But as with solar PV, the unaligned development of capacity and electricity production in Figure 11(a) and (b) indicate that there might be statistical errors. Current barriers are unattractive tariffs as well as a lack of stakeholder coordination and experience [73]. Besides increasing the quantity and quality of wind resource assessments and feasibility studies, the RUEN calls for the development of wind turbines in isolated regions, outermost islands and at the country borders [5], which might imply wind power's vital role for future rural electrification.

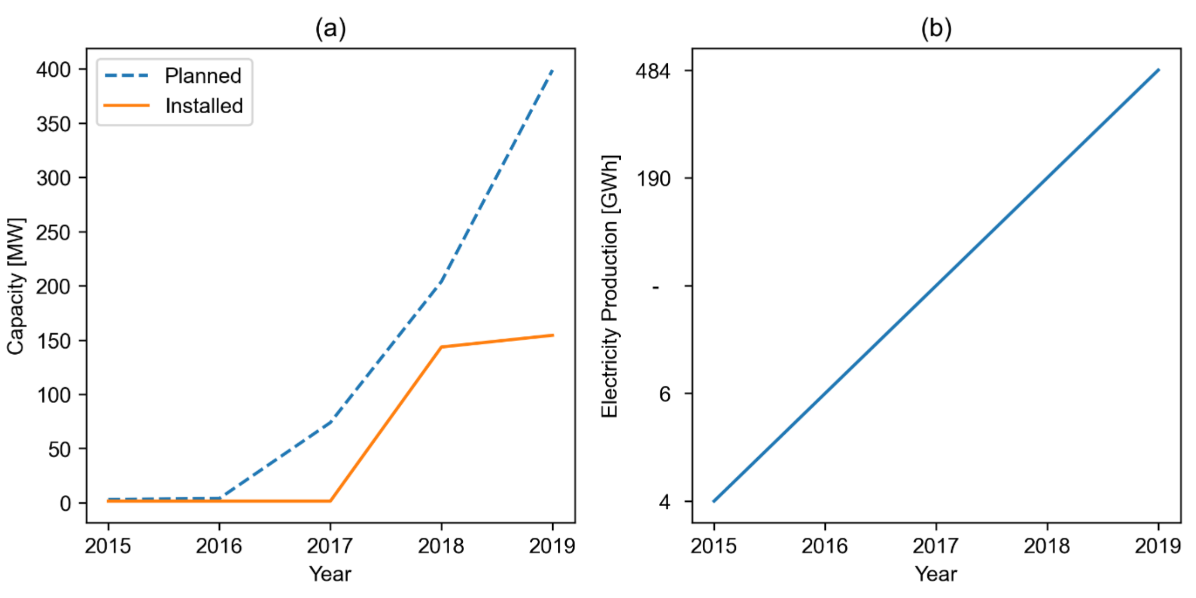

Figure 11. (a) Planned vs. installed wind capacity. (b) Electricity production from wind power [5,51].

3.6. Ocean energy

Ocean energy is the least developed RET in Indonesia and no commercial plants are operating yet. However, being the largest archipelago worldwide, Indonesia has exceptional potentials to use the energy stored in the ocean, namely through the motion of tides and waves or the thermal energy of the water. In recent reports of ESDM and the RUEN, the collective theoretical and technical potentials of ocean energy are estimated as 288 GW and 18–72 GW, respectively, though without elaboration on methods, assumptions and distinction between individual technologies [76]. The further assessment and refinement of ocean energy technologies are explicitly encouraged, and their upscaling is currently projected to start in 2025 with a target capacity in 2050 of 6.1 GW [5]. Besides ESDM, the Indonesian Ocean Energy Association *(Asosiasi Energi Laut Indonesia—ASELI)* assessed the potentials of individual ocean technologies. However, despite being frequently cited in other papers [118–121], the underlying study or seminar protocols could not be found. The internet presence of ASELI was not accessible anymore in December 2020. Thus, the primary study from ASELI could not be reviewed.

3.6.1. OTEC

OTEC generates electricity using the temperature difference between warm surface and cold deep-sea water. As a tropical archipelago, Indonesia is a very interesting country for OTEC [122–124]. Recently, the technical and economic potential of moored OTEC in Indonesia has been estimated with and without upscaling and technological learning. There, a technical potential of 102 GW_e is estimated. Without upscaling and technological learning, the economic potential is refined to 0–2.0 GW_e [18] and increases to 6–41 GW_e if these two mechanisms are included [19,125]. With a capacity factor of 91.2%, OTEC's technical and economic potential could cover up to 37% and 15% of Indonesia's electricity demand in 2050, respectively. Moreover, a nominal 100 MW_{nom} plant at 20 °C seawater temperature difference could produce around 1,200 GWh of electricity annually [126] due to real average temperature differences far higher than 20 °C of up to 25.4 °C [127].

3.6.2. Tidal power

The movement of water caused by the gravitational forces between the Earth, Moon and Sun can be exploited for electricity generation. The only estimation of tidal energy's theoretical potential in Indonesia originates from an IRENA report [128] in collaboration with ESDM and comprises 18 GW, which would be 6% of the total theoretical ocean energy potential above. Besides that, academic research focuses on local power densities [129–131] and regional potentials [132–136] of tidal current power, while studies on alternatives like tidal barrages could not be found. Among existing literature, the most researched sites are the straits in Bali, Lombok, Larantuka and Alas. In Alas, the technical potential could be as high as 2.3 GW, while Larantuka and Bali could have technical potentials between 0.2–0.3 GW and 0.5–1.0 GW, respectively [132,133]. These low potentials might be explained by suboptimal local tide properties and moderate flow velocities [135]. To the authors' knowledge, no academic or industrial work has shed light on national tidal power potentials in Indonesia yet.

3.6.3. Wave energy conversion

Wave energy converters produce electricity from the kinetic energy of waves. Within the global wave energy research network, many concepts have been studied over the last decades. Many of these designs are limitedly comparable due to technical differences [100] and uncertain design parameters [101]. For Indonesia, the oscillating wave column emerged as the most frequently studied technology and the potential of wave converters have been assessed as parts of global studies [102,103] as well as country-specifically on a national [83,101], provincial [104], cross-provincial [105,106] and local levels [107,108]. In the field of wave energy, the specific potential is usually expressed in the unit of kW/m, which represents the power per wave crest width [100]. In Indonesia, South Java is considered to have promising wave energy resources of up to 30 kW/m [101–103]. Other interesting areas are the Arafuru Sea [83], South Sumatera coastline [106] and South Kuta Bali [109]. An aggregated potential in kW is only available for individual sites [83,104], but not aggregated over provincial or national boundaries.

3.7. Potential overview and 100% RET Scenario

The national RET potentials found in literature are summarised in Table 7. Solar PV and offshore wind power have the highest technical potential in Indonesia with a capacity of 20 TW_p and 4.7 TW and electricity production of 27,540 TWh and 14,722 TWh, respectively. This would be enough to cover the demand in 2018 and 2050 more than 149 and 19 times, respectively. However, these two technologies are also amongst the least developed ones in the Indonesian electricity system and less than 1% of each potential is currently tapped. Compared to more established RET like geothermal and large hydropower, less established RET like solar PV, wind power and small hydropower were implemented slower than projected in the RUEN. Table 7 shows that ESDM's potentials do not go beyond the technical level and although definitions for practical, acceptable and economic potential exist, no publication could be found that reports these potentials for any RET.

Table 8 shows how a 100% RET electricity scenario in 2050 could be shaped with the reviewed potentials. Until 2050, large hydropower, geothermal and biomass can still be considerably scaled up. On a national level, they could comprise 6–14% of the electricity mix. Most of the electricity would have to be supplied with solar PV and wind power with a combined share of 66%. The area requirements for the necessary capacity would be limited, as only 0.5% of the marine area would be necessary for offshore wind farms, and only 0.5% of the suitable land area of solar PV parks. The conceptual feasibility of a 100% RE system is in line with recent studies on Indonesia [137–139], although there are differences in the roles of RET and land use. Compared to IESR's recent deep decarbonisation report [29], the major difference to our projection is that solar PV's role is more prominent in their work with a share of 88% in 2050.

With the reviewed potentials, such a share could have been reproduced here as well, but we decided to diversify the electricity mix over a broader set of RET with 33% of solar PV, 33% of wind energy and 33% of other RET. Compared to Simaremare et al. [137], Günther [138], and Günther & Eichinger [139], our land use shares are much smaller which can be explained by differences in regional scope. All of the three studies look into the Java-Bali region, while our scenario spans across the entire country. This shows that most RET in our scenario would not be in the economic heart of Indonesia in the Java-Bali region but the economically less developed East. Therefore, large investments in transmission infrastructure are probably required to transport the electricity produced in the East to the demand centres in the West. Moreover, creating a RET hub in East Indonesia could boost socio-economic development there and empower local communities with clean, decentralised electricity. A significant share of baseload could be provided by OTEC without interfering with land use, which is an interesting insight. Although not included in Table 8, other ocean energies like wave and tidal energy could contribute locally as well.

Note that our 100% RET scenario is just a rough projection and comes with several limitations. Besides the aforementioned necessary transmission capacity from the East to the West, the scenario does not consider the necessary storage capacity to cope with the short-term and seasonal fluctuations of solar and wind power production. Moreover, OTEC would have to be scaled up with an annual growth rate of 28% until 2050 [19,125]. The necessary growth rates for solar PV and offshore wind should be even higher. Nonetheless, the scenario shows that current energy transition plans could be reshaped towards more ambitious targets. In chapter 7, we look into the design of a fully decarbonised power system in more detail using the energy system optimisation model Calliope.

Table 7. Potential of RET in Indonesia. For references, see respective sections.

Technology		National Potential [GW_e] Theoretical ESDM	Theoretical Rest	Technical ESDM	Technical Rest	Economic ESDM	Economic Rest	Capacity Installed 2019 [GW_e]	Capacity Planned 2050 [GW_e]	Demand Coverage in 2050 [%] (tech potential)
Hydro	Large	75	241	-	26 15	-	-	5.6	38	3
	Small	19		-	-	-	-	0.4	7	
Biomass	Solid	28	16–101	-	2–18	-	-			5
	Waste	2.1	-	-	0.3	-	-	1.8	26	0.5
	Methanol	-	-	-	10–42	-	-			2–8
	Biogas	0.5	-	-	10		-			0.8
Solar PV		1,360–3,551	-	208–533	27–19,835	-	0.4	0.15	45	2–1,247
Wind		61–114	-	18–31	1,254–4,668	-	-	0.15	28	2–672
Ocean	OTEC		-		102		6–41			37
	Tidal	288	-	18–72	-	-	-	-	6.1	-
	Wave		-		-		-			-

Technology		Resources [GW_e] Speculative	Resources Hypothetical	Reserves [GW_e] Possible	Reserves Probable	Reserves Proven	Installed 2019 [GW_e]	Planned 2050 [GW_e]	Demand Coverage in 2050 [%] (tech potential)
Geothermal	ESDM	6	3	10	2	3	2.1	17.5	-
	Rest	-			42				13

Table 8. 100% RET scenario until 2050 based on the reviewed potentials.

100% RET System in 2050 (with Electricity Demand of 2,190,000 GWh [24])						
RET	**Potential (Type) [GWe]**	**Potential Electricity Production [GWh/year]**	**Share of Practical Potential [%]**	**Deployed Capacity [GWe]**	**Annual Electricity Production [GWh/year]**	**Share of Electricity Generation [%]**
Geothermal	42 (pract)	279,619	100%	42	279,619	13%
Large Hydro	38 (RUEN)	143,138	100%	38	143,138	7%
Small Hydro	7 (RUEN)	26,368	100%	7	26,368	1%
Biomass	18 (pract)	115,324	100%	18	115,324	5%
Solar PV	3397 (pract)	4,677,669	16%	530	730,000	33%
Offshore wind	2976 (pract)	8,318,237	7%	231	730,000	33%
OTEC	102 (pract)	339,045	14%	21	165,551	8%
Total	**6,580**	**13,899,400**	**-**	**887**	**2,190,000**	**100%**

4. Discussion

4.1. Limitations

Although the methods described in Section 2 yielded more than 300 publications, it cannot be guaranteed that all available literature was retrieved. The use of additional search engines, terms and techniques could have resulted in an even more comprehensive collection. Moreover, there can be a subjective bias in the classification of potentials, especially in the cases where studies did not specify the type of potential or definitions differed substantially across studies. Therefore, the differences in potentials throughout studies might stem from the underlying differences in assumptions. This was especially apparent for the reports from ESDM, where methods are not always elaborated or scattered across multiple reports. The potential definitions in Table 2 are not consistently used, which could be because different departments within ESDM use different definitions. Therefore, there are uncertainties involved about the potentials from ESDM, which this study can only point out, but not resolve. These limitations aside, this study still provides the most comprehensive overview of the general state of research on Indonesia's RET potentials so far.

4.2. Knowledge gaps

Three knowledge gaps can be identified. A first knowledge gap comprises the limited work on RET potentials in Indonesia beyond the technical level. Most potentials reviewed in this chapter originate from reports by ESDM, which do not always elaborate on the used data, methods, and assumptions. Most academic literature covers localised case studies with limited applicability to provincial and national levels. Many of these case studies were excluded from this review due to conceptual and methodological inconsistencies. If national potentials are mentioned in journal papers, they are generally directly adopted from ESDM [36,57,60,89,140]. This is reasonable as the potentials from ESDM are not only useful for review papers and energy policy planning but also provide a foundation for energy scenarios in academic research [36,42,60]. However, this study provides reasons to assume that ESDM's potentials are too conservative and therefore current strategies, like the RUEN. Although potentials can vary considerably across academic publications, they tend to be significantly higher compared to ESDM's potentials. If these academic estimations hold, Indonesia's potential to implement RET might be much larger than currently assumed. Alternative development strategies might capture these updated potentials more adequately than the RUEN enabling more progressive implementation targets. But to consolidate these arguments, more in-depth research is required.

The second knowledge gap builds upon the first one, as there is not only limited work on the potential of individual technologies but also on how these potentials interact with each other.

Outside the field of ocean energy, no study was found that assesses the potential of several RET in Indonesia simultaneously. If the applicability of RET across Indonesia was mapped, it was either done for individual technologies [18] and in the case of solar PV and wind power [15,104] solely onshore, thus excluding alternatives like floating PV and offshore wind. For ocean energy, collective potential maps exist [119,141], but they are qualitative and do not offer insights into their technical and economic performance. As a result, current literature does not offer a map of the collective potential of several RET across Indonesia and the interaction between individual technologies.

The third knowledge gap refers to the lack of thorough data on natural resources such as wind and ocean data. As mentioned in two biomass studies [30,87], datasets on the same metric could differ significantly between sources, thus affecting the results based on the choice of the dataset. Regarding wind power, both ESDM and academia agree that thorough field data is needed for more refined potentials, although the costs of acquisition are a hurdle [5,140,142,143]. This might explain why current research focuses more on local case studies since these cases can be studied more cost-effectively via simulations [113,116] or local on-site measurements [115,117]. These complications also apply to ocean energy research, as there are only a few data observation stations [144] and research is currently predominantly performed locally. None of the reviewed wind and ocean energy studies used simulated resource data from reanalysis models like HYCOM or ERA5 as a proxy for measured field data.

5. Conclusions

In this chapter, contemporary literature was reviewed to show what the potential of *Renewable Energy Technologies (RET)* in Indonesia is and how they could contribute to meeting current and future electricity demand in 2050. This study concludes that Indonesia hosts massive renewable energy resources spread over a wide range of different technologies on land and sea. Moreover, a 100% RET system could be technically feasible to meet Indonesia's future electricity demand. However, the research field is still underdeveloped and could benefit from more attention, potentially targeting the three knowledge gaps discovered in this study. First, there is limited work on RET potentials beyond the technical level with most existing knowledge originating from the Indonesian Energy Ministry (ESDM) and its subdivisions. These potentials might be too conservative based on the methodological assumptions. Second, existing studies mostly assess individual technologies and do not offer insights on the aggregated potential of multiple technologies and their distribution across the country. Third, there is a lack of thorough empirical data on natural resources such as wind and ocean data, due to which contemporary literature focuses more on local case and feasibility studies with little applicability to larger regional scopes.

The implementation of most RET, especially of unestablished ones like small hydropower, solar PV, and wind power, has proceeded slower than planned in Indonesia's national energy plan, the RUEN. This and the lack of academic and industrial research oppose the potential that RET might possess in Indonesia. Potentials from non-governmental studies tend to be much higher than the ones from ESDM. For example, the technical potential of wind power might be 260 times higher than currently projected in the national energy plan. If these projections hold, Indonesia has the luxury to choose between multiple options to promote the energy transition beyond what is already planned in the RUEN. However, due to the limited body of academic and industrial studies, more research is required to make more solid estimations of these potentials.

The assessment of RET potentials in Indonesia is a promising and worthwhile pursuit. Indonesia is a strongly growing country with the outlook of becoming one of the largest economies in the world; a development that might precipitate an equally robust growth in electricity demand. But ultimately, fossil fuel resources are finite, with Indonesian coal and natural gas being no exception. Therefore, the archipelago has splendid prerequisites to move away from fossil fuels towards a more sustainable energy system with beneficial effects beyond national borders.

6. Recommendations

Based on the literature review and three knowledge gaps found in this study, the following research and policy recommendations are proposed. The research recommendations are not ordered by relevance, but by the knowledge gaps in Section 4.2.

Assessment of RET Potentials Beyond the Technical Level

As shown in Table 7, there is only limited work on potentials beyond the technical level for virtually all reviewed technologies. To consolidate the potentials found in literature, more research on the potentials under practical and economic constraints is needed. For example, Langer et al. [18] assessed the economic potential of OTEC considering marine protected areas, water depth, connection points from sea to shore and the local electricity tariff. The methodology proposed there might be adapted for other RET, as recently done for wind power as a master thesis project at TU Delft [145].

Aggregation and Spatial Mapping of Potentials of Several RET

The potentials of individual technologies do not provide insights into how these technologies interact with each other. For instance, OTEC plants could be complemented with floating solar energy modules [146,147], but not with offshore wind turbines due to potential harmful interference of the offshore structures. Therefore, it might be helpful to pursue an integrated approach and to map the potential of several technologies across Indonesia. If multiple non-combinable technologies overlap at one location, the one with the higher potential could be preferred. Such work could connect the existing work on individual technologies, e.g., visualising the potential of wave energy conversion in South Java, while highlighting solar PV potentials in East Nusa Tenggara.

Utilisation of Simulation and Forecast Models for an Initial Potential Estimation

In literature, the collection of thorough field data is mentioned to refine the potential analyses. This might not be necessary and instead, the collection of field data could be limited to high-potential areas based on grounded estimations. For example, a preliminary assessment with data from sources like HYCOM and the Global Wind Atlas could reveal interesting areas for further investigation. For example, Namrole on Buru Island emerged as an economically interesting location for OTEC based on simulated data from HYCOM [18]. Thus, field data could be collected there to validate the simulation data, methods, and potential of OTEC.

Re-shape provincial and national targets for RET implementation until 2050

A key insight of this study is that the potential of RET in Indonesia is far higher than currently assumed by ESDM. However, current energy policies are built around ESDM's work, so the RUEN does not consider these increased potentials or even leaves out entire technologies like offshore wind. Therefore, this study recommends to re-assess current energy transition strategies to consider the potential of RET more appropriately. An important step towards this was PLN's recent pledge to become carbon neutral by 2060 [8]. To achieve this ambitious goal, the role of solar PV and offshore wind should become far more prominent as well as storage technologies to deal with short-term fluctuations in power supply. The integrated potential map discussed above and the scenarios derived from it could serve as the conceptual baseline of an updated energy transition strategy.

3. The technical and economic potential of low-wind-speed offshore wind

Abstract: The current focus of offshore wind industry and academia lies on regions with strong winds, neglecting areas with mild resources. Experience with cost reduction in photovoltaics has shown that even mild resources can be harnessed economically, especially where electricity prices are high. Here we study the technical and economic potential of offshore wind power in Indonesia as an example of mild-resource areas, using bias-corrected ERA5 data, turbine-specific power curves, and a detailed cost model. We show that low-wind-speed turbines could produce up to 6,816 TWh/year, which is 25 times Indonesia's electricity generation in 2018 and 3 times the projected 2050 generation, and up to 166 PWh/year globally. While not yet competitive against current offshore turbines, low-wind turbines could become a crucial piece of the global climate mitigation effort in regions with vast marine areas and high electricity prices. As low-wind-speed turbines are not yet on the market, we recommend prioritising their development.

Chapter 3: The technical and economic potential of low-wind-speed offshore wind

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Abbreviations, symbols, and indices

Abbreviation	Meaning
BPP	Biaya pokok penyediaan (basic costs of electricity provision)
EEZ	Exclusive economic zones
GWA	Global wind atlas
HVAC	High voltage alternating current
HVDC	High voltage direct current
LOESS	Local polynomial regression
NREL	National renewable energy laboratory
PLN	Perusahaan listrik negara
PPA	Power purchase agreement

Symbol	Meaning	Unit (if applicable)
α	Shear exponent	-
η	Efficiency	%
a	Availability factor	%
A	Area	km^2
CAPEX	Capital expenses	US$(2021) million
D	Rotor diameter	m
E	Electricity production	kWh/year
h	Hub height	m
H	Number of wind turbines inside wind farm area	-
i	Discount rate	%
l	Distance from offshore wind farm to onshore connection point	km
LCOE	Levelized cost of electricity	US¢(2021)/ kWh
m	Mass	kg
N	Lifetime	Years
OPEX	Operational expenses	US$(2021) per year
P	Power	kW
S	Spacing factor between turbines	-
v	Wind speed	m/s
X	Correction factor	-
z	Water depth	m

Index	Meaning (excluding cost components)
±20%	Variation by ±20% of reference value
100m	Hub height at 100 m
50m	Hub height at 50 m
a	Annual
c	Centroid of the wind farm
elec	Electrical
f	Factor
lat	Latitudinal
long	Longitudinal
n	Year n out of N
rated	Rated
t	Time step t
Turb	Turbine
Wake	Wake losses of the wind farm

1. Introduction

Indonesia is known for many things, but strong winds are not one of them. Compared to high-resource countries like Denmark and the UK with average 100m wind speeds of 8.5 m/s and higher, Indonesia's average is less than half, at 4 m/s. Indeed, Indonesia is amongst the most wind-poor countries globally on average [47]. Consequently, wind energy is currently not at the centre of Indonesia's energy transition [5]. However, mild renewable resources can still be harnessed economically, either via cost reductions, as has been shown by examples like photovoltaics in Finland [148], or via high local electricity prices [149], e.g. in rural and remote areas worldwide [150].

In practice, offshore wind power is becoming an increasingly exclusive technology for regions with high wind resources, while low-resource countries like Indonesia remain sidelined. To reduce electricity generation costs [151], manufacturers focus on releasing larger and larger turbines [152] designed explicitly for high-resource locations. In contrast, we could not find offshore wind turbines on the market designed for mild resources [153]. Current research on wind power potential commonly excludes mild resources using wind speed thresholds assuming limited economic viability there [110,149,154–156]. Studies including mild resources [157,158] found that low-capacity turbines are preferable in low-wind-speed regions but excluded local electricity tariffs and did not discuss mild areas specifically. As part of the "LowWind Project" at DTU Wind [159], a hypothetical, low-specific-power, low-cut-out-wind-speed turbine is studied, but only for North and Central Europe and again not for low-resource regions [160]. For Indonesia, past studies [16,34,35,110,145,161] suggested the offshore wind potential may reach up to 14,722 TWh [16], implying that mild wind resources could significantly contribute to Indonesia's energy transition. However, these studies used low-resolution wind data [16,110], one type of turbine [110,145], or excluded local electricity tariffs [16,34,110].

Current studies may not capture the impact of detailed orography on local wind profiles, and may select turbines unfit for the local conditions. Moreover, comparing the cost of energy technologies without considering local electricity tariffs disregards technologies that are comparatively more expensive, but still economically viable in regions with sufficiently high tariffs. Furthermore, wind turbines designed for low wind speeds, e.g. Swisher et al.'s [160], have not yet been studied for mild-resource regions, so the impact of such a technology for power system decarbonisation at these currently excluded regions is still unknown.

To address these shortcomings, we study the technical and economic potential of offshore wind in mild-resource regions, with Indonesia as our representative case. The focus is on turbines designed for low wind speeds, first, to draw attention to the currently overlooked but considerable potential of mild-resource regions in making a significant contribution to a rapid energy transition, and second, to understand the overall offshore wind potential in Indonesia. We use 20 years of hourly ERA5 [46] wind speed data, bias-corrected with the *Global Wind Atlas (GWA)*, and map suitable sites for offshore wind farms based on exclusion criteria. Besides two offshore turbines, we also study two low-wind-speed onshore turbines assumed to be modified for offshore application. We use turbine-specific power curves and a detailed cost model to calculate the turbines' technical and economic potential. The technical potential aggregates the annual electricity production of all wind farms mapped across Indonesia, while the economic potential only includes wind farms with *Levelized Cost of Electricity (LCOE)* equal to or below the local electricity tariff. Furthermore, we assess the sensitivity of our results to changes in site selection criteria and model parameters and show how a carbon tax could boost the technology's economic potential. We now discuss these aspects in turn.

2. Methods and materials

This section describes the methods to map the wind resources in Indonesia and calculate the technical and economic offshore wind potential. All analysed wind turbines are horizontal-axis machines situated offshore either with a fixed-bottom or floating structure. We included floating turbines in our analysis to reflect the potential of future technologies as in other studies [34,110,155]. We acknowledge the current technological and economic barriers of floating turbines. Therefore, even if our analysis yields an economic potential for floating turbines, we do not expect its materialisation in the foreseeable future. Instead, the technology will probably be developed in high-resource regions and only spill over to milder regions once sufficient experience has accumulated.

2.1. Mapping of suitable sites and wind farm sizing

We use *QGIS 3.16 Hannover* to map suitable sites for offshore wind energy, starting with a base map of Indonesia's *Exclusive Economic Zone (EEZ)*. We added exclusion layers and their buffers to the base map and removed overlapping areas. In this study, the exclusion layers contain conservation zones, water depth, shipping routes, subsea cables and visual impact, see Table 9. The output of this step is a shapefile with thousands of polygons suitable for wind farm implementation. We removed polygons smaller than 30 km^2 to ensure a sufficient wind farm size and to curb computational efforts for subsequent calculations. We divide the remaining polygons into rectangular grid cells with a resolution of 0.125°, and the polygons inside these grid cells represent one wind farm. The subdivision helps to better capture the local wind farm site conditions, like water depth and wind speed, as these values might not be represented adequately if they are averaged over a too large polygon area. Next, the centroids of the gridded polygons are obtained, which are used to store the technical and economic properties of the wind farms, like area and water depth.

Table 9. Exclusion criteria for the mapping of suitable offshore wind farm sites.

Exclusion layers [Ref]	Layer type + Resolution	Exclusion criteria	Buffer [m] [Ref]
Conservation zones [162,163]	Vector	-	1,000 [164,165]
Water depth [166]	Raster, 463 m	> 1,000 m [110,158]	None [164]
Shipping routes [167]	Raster, 555 m Rescaled to 3 km due to computational limitations	Shipping density < 5,000,000 + areas larger than 30.5 km^2	1,000 [165]
Subsea cables [168]	Vector	-	1,000 [17]
Visual impact	Vector	≥ 10 km [169]	None

2.2. Creation of bias-corrected wind speed data

We modify the approach from Staffell & Pfenninger (2016) in three ways to obtain 20 years of bias-corrected, spatiotemporally resolved wind speed data across Indonesia. First, we use the newer ERA-5 data instead of MERRA-2 data to benefit from the former's higher resolution and availability of speeds at 100 m height, which is the default hub height in this study. Second, we do not spatially interpolate to exact wind farm locations but to a finer grid, as detailed below. Third, we bias-correct wind profiles with the *Global Wind Atlas (GWA)* due to a lack of measured data. As of September 2021, there are only two operational wind farms in Indonesia [171], both being onshore. Wind resource measurement at offshore locations is also unavailable since previous measurement campaigns only took place at onshore locations at heights between 30–50 m [65]. This leads to the following procedure:

1. Download 20 years of ERA5 wind speed data at a height of 100 m with a resolution 0.25° and remove outliers.
2. Interpolate linearly between the data points for a finer grid resolution of 0.125°.
3. Bias-correct the wind profiles with GWA data.

2.2.1. Download and pre-processing of wind speed data

The setup in Table 10 is used to download 20 years of ERA5 wind speed data for Indonesia. The timespan was chosen to cover the commonly assumed [158,172,173] useful lifetime of a wind farm, but we acknowledge that the timespan could be extended to 25 [174,175] or 30 years [155]. ERA5 includes both horizontal wind components U=(ux; uy), and both eastward and northward wind speeds must be used to obtain the resulting wind. Outliers are detected with a moving two-week average and replaced via linear interpolation, which affected 0.5% of the total dataset. The dataset is cleaned from outliers while keeping extreme wind speeds caused by rare extreme weather phenomena like tropical cyclones. The output of this step is a cleaned 20-year dataset of hourly wind speed data in a spatial resolution of 0.25° at a height of 100 m.

Table 10. Metadata of ERA5 wind speed data used in this study.

Title	Wind Speed Data
Name	ERA5 hourly data on single levels from 1979 to present
Creator	Hersbach et al. (2018) [46]
Downloaded from	Copernicus Climate Change Service (C3S) Climate Data Store
Web Link	https://cds.climate.copernicus.eu/cdsapp#!/dataset/reanalysis-era5-single-levels?tab=form
Coordinate system	World Geodetic System1984 (WGS84)
Coordinates	92° E to 142° E; 8° N to 13.9° S
Spatial resolution	0.25° x 0.25°
Data type	Point
Retrieved data	Eastward wind speeds at 100m *u100* Northward wind speeds at 100 m *v100*
Parameter unit	m/s
Time period	01 January 2001 00:00 to 31 December 2020 23:00
Temporal resolution	1 hour

2.2.2. Interpolation of wind speed data and bias-correction

As discussed in Staffell & Pfenninger [170], available reanalysis datasets have a rather low spatial resolution. Therefore, they require bias correction to reflect the impact of the local orography. In this study, bias correction occurs in two steps, namely (1) interpolation between ERA5 points and (2) calculation of correction factors.

Step (1) is visualised in Figure 12 and elaborated further in this paragraph. In short, we assign each wind farm centroid to its closest point on a finer-meshed grid of 0.125 degree resolution, then linearly interpolate from the native 0.25 degree ERA5 grid to the wind farm grid points where needed (i.e., where a wind farm actually exists). We acknowledge that this approach comes with limitations. The furthest distance between a centroid and a data point is roughly 10 km (The hypotenuse of a triangle with the length of the two legs being 13.9 km/2 = 6.9 km). So in the worst case, two wind farms share one wind profile despite being almost 20 km apart from each other. However, this limitation is addressed with the bias correction using GWA data (see main text). In the following we describe in detail how the interpolation procedure is implemented. First, the coordinates of the ERA5 data points are extracted. For every data point, a numerical code written with *Matlab R2020b* tries to form a square with its neighbours, with the data point being at the bottom left corner. The data point receives a rectangle index, with which the rectangle is identified later. Next, the script checks whether there are any wind farm centroids inside the rectangle. If so, then the wind speed data in the corners of the rectangle are interpolated linearly in a resolution of 0.125° or roughly 14 km for all time steps, resulting in a total of nine wind speed profiles per rectangle. Each of the nine data points receives an x-index and y-index. The interpolated wind profiles and their indices are saved in a separate file. Next, the script loops through all wind farm centroids and adds the three indices of the data point closest to the centroid. With the three indices, the wind farm centroid can be matched with the correct wind profile without compromising the data structure of the involved files for later processing steps. Moreover, computational efforts are reduced, as interpolation is only performed where necessary. Centroids that are assigned to the same data point share one wind profile, therefore the size of the file that stores the wind profiles is limited as well.

In step (2), the profiles are bias-corrected with a factor based on a high-resolution wind map. We use GWA 3.0 [47], which maps wind speeds with a spatial grid size of 250 m at various heights and uses underlying high-fidelity wind resource hindcast datasets and measuring campaigns for validation, amongst others from Papua New Guinea. There, the average mean absolute bias across three measurement stations was 12% ±10% standard deviation. As Papua New Guinea borders East Indonesia, the bias and thus the wind map are deemed acceptable for this research [176]. We follow Bosch et al. [34] and use a time-invariant, constant correction factor for each wind farm centroid. As the GWA map shows average wind speeds from 2008–2017, the interpolated ERA5 wind profiles are averaged for this period and then compared to the GWA values. The correction factor is then deduced from the deviation of the two averages. For example, if the GWA wind speed at a given centroid is 25% higher than the average interpolated ERA5 wind speed, each value of the wind profile is increased by 25%.

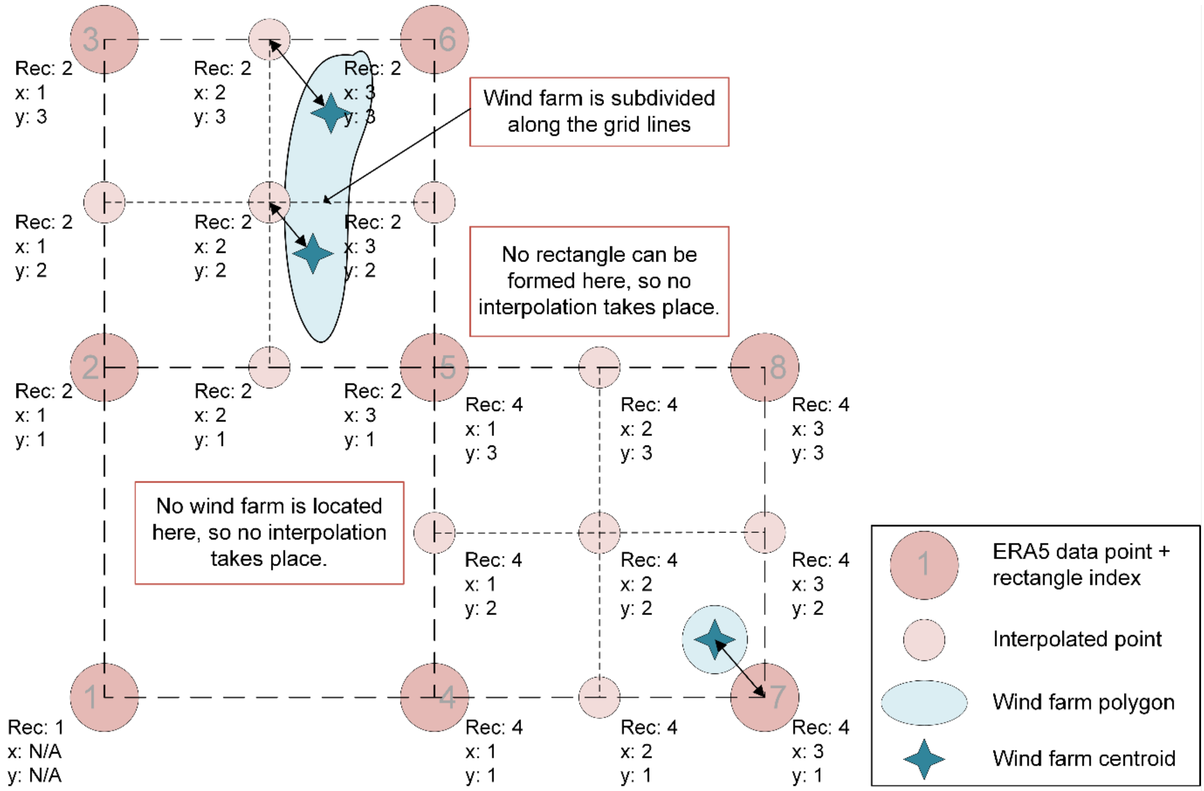


Figure 12. Interpolation of ERA5 wind speed data and indexing convention to connect wind farm centroids with wind speed profiles

2.3. Technical and economic analysis of offshore wind power

2.3.1. Levelized cost of electricity and choice of turbines

In this sub-section, we summarise our approach for the technical and economic analysis using Eq (1–6) and Table 11. We calculate the *Levelized Cost of Electricity (LCOE)* per wind farm in 2021 values using the currency conversion rates in Appendix B. The LCOE indicates the necessary electricity tariff to break even with all project costs at the end of the project's useful lifetime. The project costs consist of *Capital Expenses (CAPEX)* and *Operational Expenses (OPEX),* and their calculation is explained in the next sub-section. The annual electricity production E_a is computed as a function of wind speed v, the distance between the wind farm to an onshore connection point l, the availability factor a_f, and the number of wind turbines H [158]. Furthermore, the electrical losses from the inter-array and transmission infrastructure η_{elec} are calculated. Depending on the distance, either *High-Voltage Alternating Current (HVAC)* cables at 220 kV or *High-Voltage Direct Current (HVDC)* cables at 320 kV are assumed [152]. The default hub height in this study is 100 m [158]. If a turbine cannot operate at such height, e.g. due to too long rotor blades, the wind speed v is scaled for the alternative height using the power law. The local shear exponent α is calculated with GWA data at 50 and 100 m height [177].

$$LCOE_c = \frac{CAPEX_c + \sum_{n=1}^{N} \frac{OPEX_{c,n}}{(1+i)^n}}{\sum_{n=1}^{N} \frac{E_{a,c,n}}{(1+i)^n}} \tag{1}$$

$$E_{a,c,n} = \sum_{t=1}^{T} P_{Turb}\left(v_{c,t,n}\right) * H_c * \eta_{elec}(l_c) * \eta_{Wake} * a_f \tag{2}$$

$$H_{c,Turb} = \frac{A_c}{S_{long} * D_{Turb} * S_{lat} * D_{Turb}} \tag{3}$$

$$with\ \eta_{Trans,c} = \begin{cases} 0.979 - 1 * 10^{-6} * l_c^2 - 9 * 10^{-5} * l_c, & l_c \leq 50\ km \\ 0.964 - 8 * 10^{-5} * l_c, & l_c > 50\ km \end{cases} \tag{4}$$

$$v_{x,c,t} = v_{100m,c,t} * \left(\frac{h_{\pm x}}{h_{100m}}\right)^{\alpha_c} \tag{5}$$

$$\alpha_c = \frac{\ln\left(\frac{v_{100m,c}}{v_{50m,c}}\right)}{\ln\left(\frac{h_{100m}}{h_{50m}}\right)} \tag{6}$$

Variables
α: shear exponent
η: efficiency
a: availability
A: area of wind farm
CAPEX: capital expenses
D: rotor diameter
E: electricity production
H: number of wind turbines in a wind farm
h: hub height
i: discount rate
l: distance from wind farm to onshore connection point
N: lifetime
OPEX: operational expenses
P: power output of one turbine based on the power curve
S: spacing between turbines in a wind farm
v: wind speed

Indices
100m: hub height at 100 m
50m: hub height at 50 m
a: annual
c: centroid of the wind farm
elec: electrical
f: factor
lat: latitudinal
long: longitudinal
n: year *n* (out of *N*)
t: time step *t* in year *n* (out of *T* = 8,760 hours/year)
Turb: turbine
Trans: transmission
Wake: wake effects of the wind farm
x: hub height at x meters

Table 11. General and turbine-specific techno-economic assumptions used in this study.

General Assumptions [Ref]				
Discount rate i [%]	10 [66,178]			
Lifetime N [years]	20 [158,172,173]			
Wake efficiency η_{Wake} [%]	88 [34,172,179]			
Availability factor a_f [%]	90 [110,165]			
Turbine spacing S_{long}×S_{lat} [-]	10D×10D [158]			
Turbine-specific assumptions (all information from [153] **and** [180]**)**				
Commercial name	SG2.1-114	GW140-3400	SWT-6.0-154	IEA 15 MW RWT
Name used here	2.1MW-D114	3.4MW-D140	6.0MW-D154	15MW-D240
Rated power [kW]	2,100	3,400	6,000	15,000
Assumed hub height [m]	100	100	100	150
Cut-in wind speed [m/s]	1.5	2	4	3
Rated wind speed [m/s]	9	10.5	13	10.6
Cut-out wind speed [m/s]	25	20	25	25
Rotor diameter [m]	114	140	154	240
Capacity density [MW/km^2]	1.6	1.7	2.5	2.6
Wind class	IEC IIA/IIIA/S	IEC IIIA	IEC IA	IEC IB
Onshore/ offshore application	onshore	onshore	offshore	offshore
Direct drive	no	no	yes	yes
Ratio of generator capacity to swept area [W/m^2]	206	221	322	332

We use the power curves $P_{Turb}(v)$ of four turbine models from the Wind Power database [153] and IEA 15 MW reference turbine [180] to calculate E_a. The latter turbine is included to reflect the trend of the offshore wind industry for increasingly larger turbines with greater rated power and longer rotor blades [181]. Instead of their commercial names, we use a standardised terminology of *'[rated power]MW-D[rotor diameter]'* to refer to turbines. The turbines are selected to have a variety of rated power, rotor diameter, and cut-in, rated, and cut-out wind speed. The power curves are not smoothened as in other studies [170,182] to avoid an overestimation of electricity production, as the smoothened power curves can entail a higher power output at low wind speeds [182,183].

Our wind farm model comes with several limitations. Regarding the availability factor a_f, the operation and maintenance strategy depends on the design of the wind farm [184]. But due to limited data on service ports and vessel availability, amongst others, we decided to use a simplified general factor of 90% [110,165], which is comparatively conservative [185,186]. Moreover, we do not model the inter-array infrastructure in detail but incorporate it in the total electrical efficiency η_{elec}. The inter-array infrastructure costs are included in the cost components "electrical connections" and "marinisation" in Appendix C. For transmission lines, we assumes straight lines from plant to onshore connection without the ducting of the lines under water. Depending on the complexity of the seabed structure and local metocean conditions, the transmission costs might be considerably higher. Losses from transformers, converters, and others are assumed to be constant, while losses in the transmission cables only depend on the distance to shore. Another limitation is the use of a general turbine spacing of *10D×10D* [158] with wake losses of 88% [34,172]. These values are rather conservative compared to spacings [155] and wake losses in literature [155,165]. Given Indonesia's size, it was computationally not feasible to optimise the spacing and wake losses for each wind farm, which could improve the technical and economic results presented here. Lastly, we use hourly wind speed data and match them to the power curves that are derived for different time intervals, like 10 minutes. Therefore, the electricity production might vary from the results shown here if these discrepancies would be addressed.

Note that all turbines suitable for IEC wind class III are onshore turbines. Since there are currently no IEC wind class III offshore turbines on the market, the power curves of the onshore turbines are used for offshore application. For the sake of the analysis, we argue that the onshore turbines could be modified for offshore use and deployed with an adequately designed support structure and tower to withstand wave loading forces. These requirements are incorporated into the cost model in the next sub-section. For completeness, we also include one offshore turbine to show the technical and economic potential of existing offshore turbines.

2.3.2. Cost model for fixed-bottom and floating wind farms

We use the mass-based cost model developed by the *National Renewable Energy Laboratory (NREL)* [187]. CAPEX and OPEX can be calculated based on rotor diameter, hub height, rated power, and drivetrain type. The model found application in academic literature [173,188] but also faced criticism. Rinne et al. (2018) rightfully pointed out that the methodology is somewhat outdated given that it was developed in 2006. Updating the cost functions with industrial data is challenging, as almost all project contracts are confidential [151,190]. Moreover, using constant system cost factors per rated power [155,191] can lead to inaccurate cost estimations as they exclude location- and turbine-specific influences on cost. Therefore, we propose two modifications to bring NREL's cost model up to date.

First, we replace the cost functions of some components with more recent functions and values from literature. The offshore structure costs were originally only based on the turbine rating but now also consider water depth. At depths of up to 25 m, the model assumes monopile structures. The model switches to jacket structures at depths between 25–60 m as the more cost-efficient option [17]. At depths between 60–1,000 m, the model assumes floating, semi-submersible structures [174]. We use these thresholds based on literature, but we acknowledge that they shift with the state of the art as monopoles can be deployed at depths of up to 40 m nowadays [192]. Power transmission costs are originally based on the turbine rating, but now they also consider the distance from the wind farm to the onshore connection point. At distances of up to 50 km, HVAC cables are used, and at further distances, HVDC cables are used. Furthermore, transportation, port and staging equipment, and installation cost originally footed on the turbine rating. Here, they are summarised under one cost component and calculated on a per-turbine basis [17,184] with most recent industry data [174].

Second, we calibrate the cost model with technology-specific correction factors derived from the most recent cost review report by NREL [174]. We believe that the location- and technology-specific costs for fixed-bottom and floating wind farms can be adequately estimated with these modifications. Appendix C shows the original cost functions and all modifications.

As with the technical assumptions, the cost model and surrounding assumptions come with limitations. First, we exclude costs for the extension of the local power grid unlike other studies [184,191,193]. Second, some site-specific conditions could not be included in the cost model, like the influence of seabed properties on structure costs. Hong & Möller [165] assumed 40% higher structure costs in China than in Europe due to different seabed properties. We refrained from such general assumptions as seabed properties vary across Indonesia. On the western side of Indonesia, sea beds consist of sand, silt, mud, and calcareous ooze while the eastern part also contains large areas of siliceous ooze and clay [194]. We also excluded local wave behaviour in the cost model as waves in Indonesia are rather low [144] and within the operational limits of most vessel operators [195]. Third, our cost model can only provide a rough estimation of the turbine- and location-specific costs despite the modifications described above. Cost components like OPEX and installation costs are simplified and exclude aspects like proximity to service harbour, vessel cost, as well as personnel [17,184]. Moreover, our cost model does not reflect the cost developments from (1) wind farm upsizing and (2) technological learning. Regarding (1), we assume no cost savings due to wind farm upsizing [190,193]. However, we acknowledge the ongoing discussion on this topic and the studies that argue otherwise [151,184,196]. Regarding (2), technological learning could be studied with learning rates by creating implementation scenarios, which is beyond the scope of this work. Furthermore, cost developments depend on the local policy environment [190] and commodity prices [197], amongst others. It is yet unclear how costs will develop in Indonesia, where wind energy is still a nascent technology. Therefore, our cost estimations and their developments must be reassessed when more practical data for Indonesia become available.

Despite the limitations described above, we believe that this study still produces valuable first results, which might spark further, in-depth research in the future.

2.4. Grid connection and local electricity tariffs

We connect wind farms either to Indonesian cities of the varying administrative levels or substations at 70 kV and above. From a private perspective, it would be reasonable to exclude off-grid areas, as it is not the responsibility of wind farm developers to build and maintain public grid infrastructure. Nonetheless, we still include them to reveal interesting locations for national grid extension and rural electrification.

The local electricity tariff can be assigned once a wind farm is connected to a city or substation. In Indonesia, the tariff for renewable electricity production is based on *Power Purchase Agreements (PPA)* between the power plant operator and Indonesia's state-owned utility company *Perusahaan Listrik Negara (PLN)*. The maximum receivable tariff is capped by the *Biaya Pokok Penyediaan (BPP – Basic cost of electricity provision)*. The BPP reflects the electricity generation costs and is calculated for regions and the entire country. If the regional BPP is higher than the national BPP, a wind farm operator may receive up to 85% of the regional BPP. If the national BPP is higher than the regional BPP, the maximum receivable tariff is based on business-to-business negotiations. Since the details of the PPA are confidential, there is no reliable data on currently viable tariffs. Therefore, we assume that all wind farms receive 85% of the regional BPP. The set of regional BPP of 2018 ranged between 6.91–21.34 US¢(2018)/kWh [198], leading to receivable tariffs of 6.20–19.14 US¢(2021)/kWh depending on the location.

With the regional electricity tariffs, the economic wind potential is the aggregated rated power of all wind farms with an LCOE equal to or below the local electricity tariff. Although useful for this study, a limitation of this approach is that the 85% of regional BPP only serve as a price cap and depending on the negotiations with PLN, and the actual receivable tariff might vary. Moreover, Indonesia's renewable energy policies undergo frequent reforms [56], and it is unclear whether and how long the current PPA scheme will exist.

2.5. Sensitivity analysis

To address the limitations elaborated above, we conduct a sensitivity analysis to understand their impact on the results better. First, we study how changes in site selection criteria affect the average LCOE, technical potential, and economic potential. We also add a carbon tax to the electricity tariffs to see how the economic potential per turbine changes. Second, we vary the representative model by ±20% to show the change of average LCOE, technical potential, and economic potential. The studied parameters are CAPEX, OPEX, wind speed, discount rate, hub height, and total efficiency including availability factor, as well as transmission and wake losses. For the adjustment of the wind speed for varying hub heights, we again use the power law as described earlier.

3. Results and discussion

3.1. Technical potential of offshore wind in Indonesia

First, we quantify the technical potential by selecting wind turbine model power curves, quantifying the available area for them through geospatial analysis, and combining the two to compute aggregate total wind potentials for Indonesia. We consider four different turbines, for which we use the labelling terminology *[rated power]MW-D[rotor diameter]* for the remainder of the chapter. The *2.1MW-D114* and *3.4MW-D140* are onshore turbines designed for mild wind resources, and are assumed to be modified for offshore application (see methods section). The *6.0MW-D154* and *15MW-D240* are offshore turbines that reflect the current state and outlook of the industry. The average capacity factors vary significantly among the turbines, with 35% for the *2.1MW-D114*, 20% for the *3.4MW-D140*, 9% for the *6.0MW-D154*, and 15% for the *15MW-D240*. These capacity factors are below the average factor of 43% from existing offshore wind farms [199]. However, the highest capacity factors are 60% for the *2.1MW-D114* and 43% for the *15MW-D240*, which are competitive to the average values expected in 2050 [199,200]. The differences in wind profiles and turbines (see Figure 13) cause the wide range of capacity factors. The average wind speed in Indonesia virtually never exceeds 10 m/s. Moreover, turbines with high cut-in and rated wind speed, like the *6.0MW-D154*, rarely operate at rated power. Although the *15MW-D240* shows a better technical performance than the *6.0MW-D154*, it cannot compete with the two modified low-wind-speed turbines. This underscores that current offshore turbines are unsuitable for mild resource regions and that expected future developments in turbine upsizing might not fully address this issue. To better capture mild wind resources, offshore turbines would need a combination of low cut-in and rated wind speed, like the *2.1MW-D114* with 1.5 m/s and 9 m/s, respectively. In Figure 13, the *2.1MW-D114* operates almost continuously at partial load with the average wind profile and at sustained full load in high-resource locations.

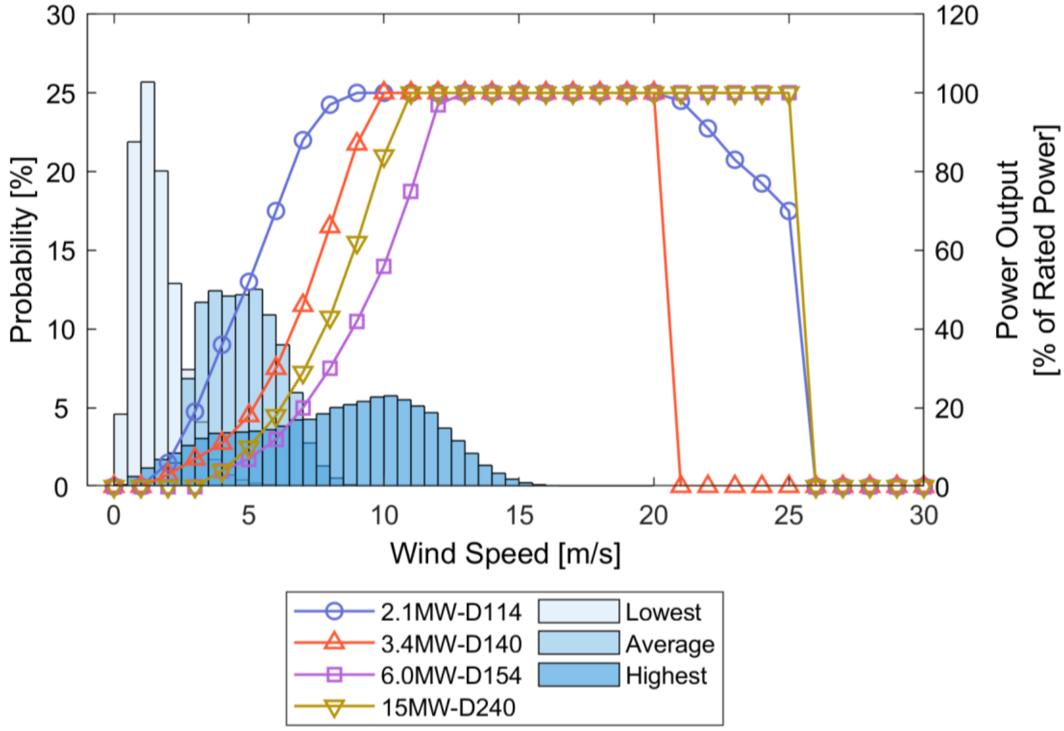


Figure 13. Comparison of representative wind profiles at 100 m height in Indonesia with the four used power curves (normalised to rated power) [153]*. The three histograms refer to the wind profiles with the lowest and highest average wind speed and an average profile of all wind farms across Indonesia* [47]*. For clarity, the wind profiles at 150 m hub height relating to the 15MW-D240 are not shown here.*

Next, we need to place these turbines in feasible locations. Table 12 summarises the criteria used for site selection and their impact on the excluded marine area and potential. Water depth is the most restrictive criterion despite choosing a threshold depth of 1,000 m, which implies the use of floating turbines. If we restrict the threshold to 55 m depth, i.e. excluding floating turbines, 71% of the total marine area would be removed. Visual impact and shipping routes are not as restrictive, showing that offshore wind power might only have a limited effect on other sectors like tourism, real estate, and shipping. With all exclusion criteria in place, 1.3 million km^2 of marine area are available for 2.1–3.4 TW of offshore wind capacity.

Table 12. Impact of exclusion criteria on marine area and technical potential. The percentage of excluded area foots on the total marine area of 6,020,917 km^2 within Indonesia's Exclusive Economic Zone (EEZ) [111]. *"Data availability GWA" refers to the areas of Indonesia's EEZ not covered in the Global Wind Atlas (GWA), which is used for bias-correction of the ERA5 wind speed data. The excluded technical potential is based on the range of capacity densities of the studied turbines. The excluded area and technical potential per criterion do not add up to the values in "All criteria combined" because some layers overlap. * excluded area rises to 71% if limiting to 55 m water depth, which would exclude floating turbines.*

Exclusion criterion	**Excluded area [km^2]**	**Percentage of the total area [%]**	**Excluded technical potential [GW]**
Water depth	3,492,734	58 % (71%*)	5,588–9,081
Data availability GWA	935,947	16 %	1,498–2,433
Visual impact	660,764	11 %	1,057–1,718
Shipping routes	581,730	10 %	931–1,512
Conservation zones	254,405	4 %	407–661
Subsea cables	114,128	2 %	183–297
All criteria combined	**4,691,716**	**78 %**	**7,507–12,198**

Combining wind turbines and areas and modelling their generation (see methods), we estimate the technical potential in terms of annual electricity production. We find that low-wind-speed offshore turbines could produce much more electricity in Indonesia with 6,816 TWh/year than currently available offshore turbines like the *6.0MW-D154* with 2,946 TWh/year. This range could cover Indonesia's electricity generation in 2018 [1] 11–25 times and the projected generation in 2050 [24] 1.3–3 times. In relation to Indonesia's total *Exclusive Economic Zone (EEZ)*, the production density is up to 1.1 GWh/year/km^2. If this density is applied to the global EEZ for an order-of-magnitude estimation, the global technical potential would be 166 PWh/year, or 7 times the global electricity consumption in 2019 [201]. Therefore, low-wind-speed offshore turbines could have a significant impact on the global energy transition.

Our potentials deviate from the ones in literature. The Royal Dutch Shell's database [35] gives an offshore wind potential of 3,937 TWh using a minimum wind speed of 8 m/s as described in the study underlying the database [110]. With such a threshold, our technical potentials would be much lower with 2.6–3.2 TWh, which could be explained by the (1) low resolution of the input data, (2) higher capacity density of 7 MW/km^2, and (3) power generation function in Deng et al. (2015). Bosch et al.'s (2018) potential of 8,300 TWh/year may be larger than ours due to the (1) higher availability factor, (2) exclusion of transmission losses, and (3) less restrictive site selection. The differences across studies show the importance of transparency about the assumptions and their impact on results.

3.2. Economic potential of offshore wind in Indonesia

For the economic potential, we calculated the LCOE for each wind farm, compared them to the local electricity tariff, and aggregated the annual electricity production of all farms with LCOE lower than or equal to the tariff. Figure 14 shows the supply curves per turbine. The *2.1MW-D114* performs the best economically and could produce 1,626 TWh/year at an LCOE below 20 US¢(2021)/kWh. All other turbines show steeply increasing LCOE due to the comparatively low electricity production. The LCOEs in Figure 14 are far higher than the average LCOE of 8–13 US¢(2018)/kWh observed in practice [199,202]. Recent wind farms benefitted from deployment in high-resource areas and cost reductions via turbine upsizing [151], so it is unclear whether such cost reduction rates are feasible for low-wind-speed, low-capacity wind turbines in mild regions. Nonetheless, we believe that the further development of such turbines could lead to cost reductions and thus improve their economic competitiveness.

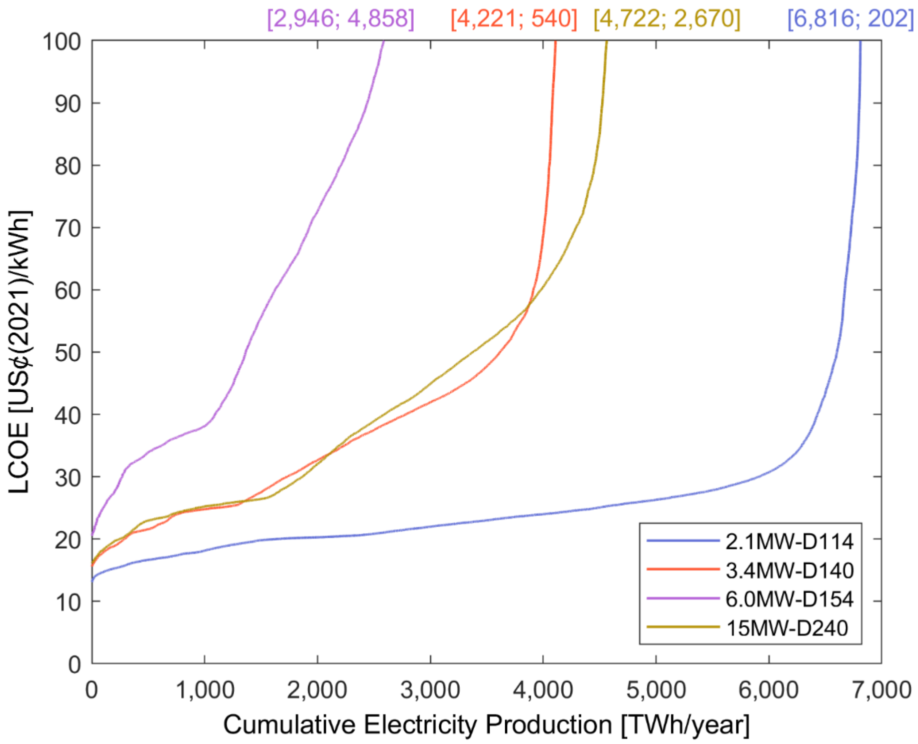


Figure 14. Supply curves for each turbine. The y-axis is limited to 100 US¢(2021)/kWh to improve readability of the plot. The end points of the plots are indicated at the top of the chart in [TWh/year; US¢(2021)/kWh].

Figure 15 visualises the wind farms' location and LCOE for the *2.1MW-D114*. LCOE are below 20 US¢(2021)/kWh on Papua, Maluku, and the southern part of Kalimantan. Between the islands of Java and Kalimantan, the impact of shipping routes is clearly visible. Especially at the harbour in Surabaya on Java, many ships head to and from Indonesia's islands and therefore necessitate the careful planning of offshore wind farms.

Considering the current local electricity tariff, only wind farms on Papua, West Papua, and Maluku bear economic potential, outlined in green in the figure. The total economic potential varies significantly across turbines and reaches 784 TWh/year for the *2.1MW-D114*, 22 TWh/year for the *3.4MW-D140*, 0 TWh/year for the *6.0MW-D154*, and 5.6 TWh/year for the *15MW-D240*. The turbines with economic potential could cover the local electricity generation of 2.4 TWh in 2018 [1] 2.3–327 times. Hence, low-wind-speed turbines could still be economically viable as the limited competitiveness against current offshore turbines is compensated by high electricity tariffs.

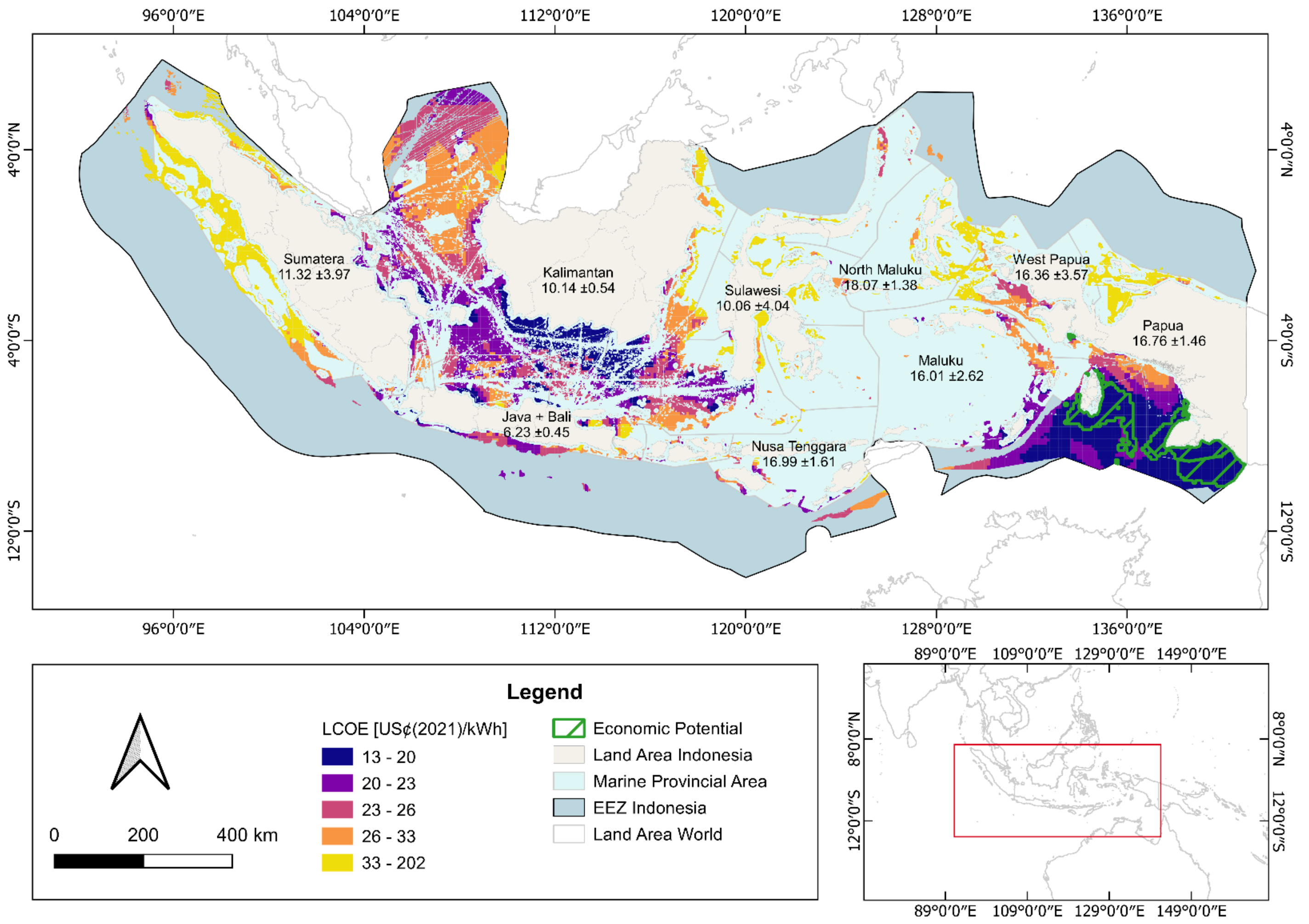


Figure 15. Offshore wind farms in Indonesia and their LCOE for the 2.1MW-D114. Wind farms with economic potential are framed in green. The LCOEs in the legend are scaled and coloured by quartiles. The average local electricity tariff and its standard deviation are shown in US¢(2021)/kWh for each island group.

We show that 100% renewable electricity could be economically feasible in three abovementioned provinces, at least from a resource perspective. Then again, only a tiny fraction of the economic potential could be materialised in practice due to the low local electricity demand in these rural areas. High-demand, low-tariff regions like Java and Sumatera are not economically feasible, at least without further policy support as we show in section 3.3.

Figure 16 presents the results of two wind farms, one close to Java with high electricity demand and the one with the lowest LCOE on Papua. On Papua, two of the four turbines are economically feasible against the local tariff of 16.33 US¢(2021)/kWh. Meanwhile, none of the turbines bear economic potential on Java, despite a just slightly higher LCOE. The specific CAPEX of 3,302–4,169 US$(2021)/kW harmonise with the values found in literature [174,203]. The cost reductions from turbine upsizing in Figure 16 align with experts' expectations [204] and the manufacturers' ambitions to scale up their turbine ratings [151]. For the *6.0MW-D154*, the relative cost savings are outweighed by its limited electricity production on both Java and Papua. The installation cost and OPEX are far higher for the *2.1MW-D114* than for the other turbines due to its small capacity density and increased demand for maintenance. With 114 turbines at sample site 1 and 23 turbines at sample site 2, the installation and maintenance processes are more time- and labour-intensive. Due to the high productivity of the *2.1MW-D114*, we expect faster fatigue of system components and thus more frequent maintenance, overhaul, and reparation activities, which we account for using a kWh-based OPEX component.

The estimates presented here should be considered first-of-a-kind figures. The cost of the first installations is likely to be significantly higher given that in Indonesia, the necessary infrastructure and equipment to install, operate, and maintain offshore wind farms does not exist yet, and collaboration with experienced, international partners might be required. Therefore, costs are highly uncertain, and our results only serve as indicative projections. Furthermore, further investigations would be necessary to ensure that the sites in Figure 16 are accessible for installation vessels given the water depth of only 2.5 and 7.6 m. We turn to the sensitivity of model results to uncertain assumptions next.

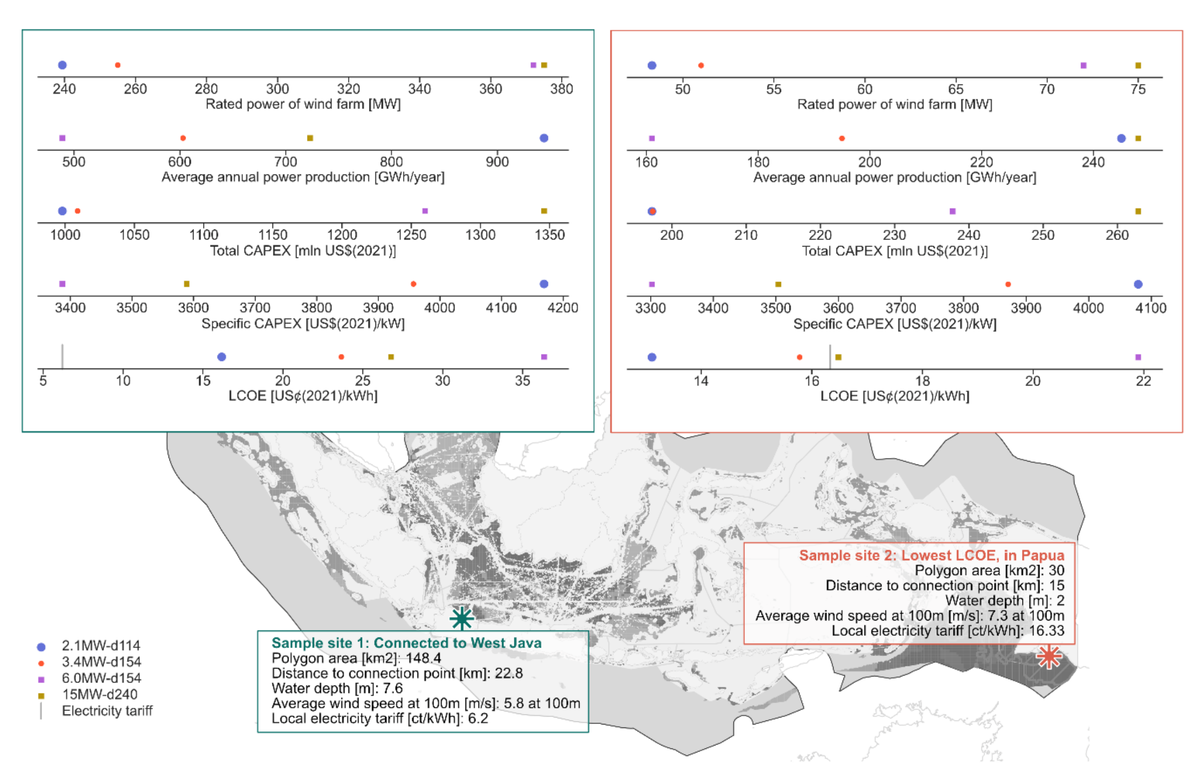


Figure 16. Technical and economic results per turbine at two sites, one close to Java with high electricity demand and the one with the lowest LCOE on Papua. This illustration was made by Dr Stefan Pfenninger, co-author of the paper underlying this chapter.

3.3. Sensitivity to site selection criteria and a carbon tax

This section elucidates the impact of site selection criteria and a carbon tax on the technical and economic potential as well as on the average LCOE per turbine. Figure 17(a) shows that the LCOE of the *2.1MW-D114* is the least sensitive to changes in minimum average wind speed, while the LCOE of the *6.0MW-D154* is the most sensitive. A threshold below 4 m/s is quite ineffective for the technical and economic potential due to the limited power production at such speeds. However, at thresholds above 4 m/s, the potentials decline drastically. Therefore, we argue that thresholds of 7 m/s and higher as used in literature [110,154,205] might be too restrictive. Instead, we recommend a threshold of 4 m/s as already done by Peña Sánchez et al. (2021).

As shown in Figure 17(b), there are still significant potentials at distances to the onshore connection beyond 100 km. Due to the Sunda Shelf and Sahul Shelf, the waters remain shallow in large parts of Indonesia, even far offshore. These shelves also explain why the average LCOE continuously decreases with distance. Far offshore, wind speeds are higher, and the increased power production makes up for the increased transmission costs and losses. Then again, the decline might not be as steep with distance-dependent cost functions for installation and maintenance, which was not possible due to a lack of data. Since visual impact is an important factor for the social acceptance of wind power [154,155,169], stricter distance restrictions could have been deployed with limited technical and economic implications, which is a positive outcome of our study.

Figure 17(c) shows the negative impact of water depth on LCOE due to steeply increasing offshore structure costs. The technical potential is almost equally distributed among fixed-bottom turbines, floating turbines at depths above 100 m, and floating turbines up to a depth of 1,000 m. This shows the interesting geographical contrasts in Indonesia, as there are not only the abovementioned continental shelves with shallow waters but also large deep-sea regions with depths below 7,000 m, like the Banda Sea [166]. However, floating turbines can probably not harness mild wind resources economically in the near future, as none of our floating wind farms bear economic potential. Nonetheless, we recommend the technology's re-evaluation given its continued development.

Figure 17(d) illustrates the change in economic potential if a carbon tax was added to the current electricity tariffs as computed in Supplementary File 1. The curves indicate an S-shaped increase of economic potential with convergence towards the technical potential. All studied turbines show a noticeable rise of economic potential at tax rates below 100 US\$(2021)/tCO_2e, except for the *6.0MW-D154*. This shows that turbines unsuitable for mild wind conditions would not be economically attractive even with strong policy support.

With sufficiently high carbon tax rates, wind power could hold a more prominent role in Indonesia than currently envisioned [5], from a niche solution for rural areas to a key option for nationwide power system decarbonisation. At 100 US\$(2021)/tCO_2e, up to 2,965 TWh/year become economically, now also on Sulawesi and Kalimantan. On Java and Sumatera, offshore wind becomes attractive at 150 US\$(2021)/tCO_2e, leading to a total economic potential of up to 4,371 TWh/year. Lifting offshore wind's economic viability on these islands is important, as electricity demand is much higher there than in the rural east. If restricted by demand, the economic potential grows from 2.4 TWh/year without a carbon tax to 34 TWh/year with a tax of 100 US\$(2021)/tCO_2e, and to 153 TWh/year with a tax of 150 US\$(2021)/tCO_2e. These potentials would cover 1%, 12%, and 55% of the electricity generation in 2018 [1], respectively. While a tax of 150 US\$(2021)/tCO_2e is similar to the ones in Sweden, Switzerland, and Liechtenstein [207], it is significantly higher than Indonesia's carbon tax of 2.1 US\$(2021)/tCO_2e effective from April 2022 [208]. Therefore, Indonesia's policymakers would have to introduce more ambitious tax rates to materialise offshore wind's economic potential beyond the rural east.

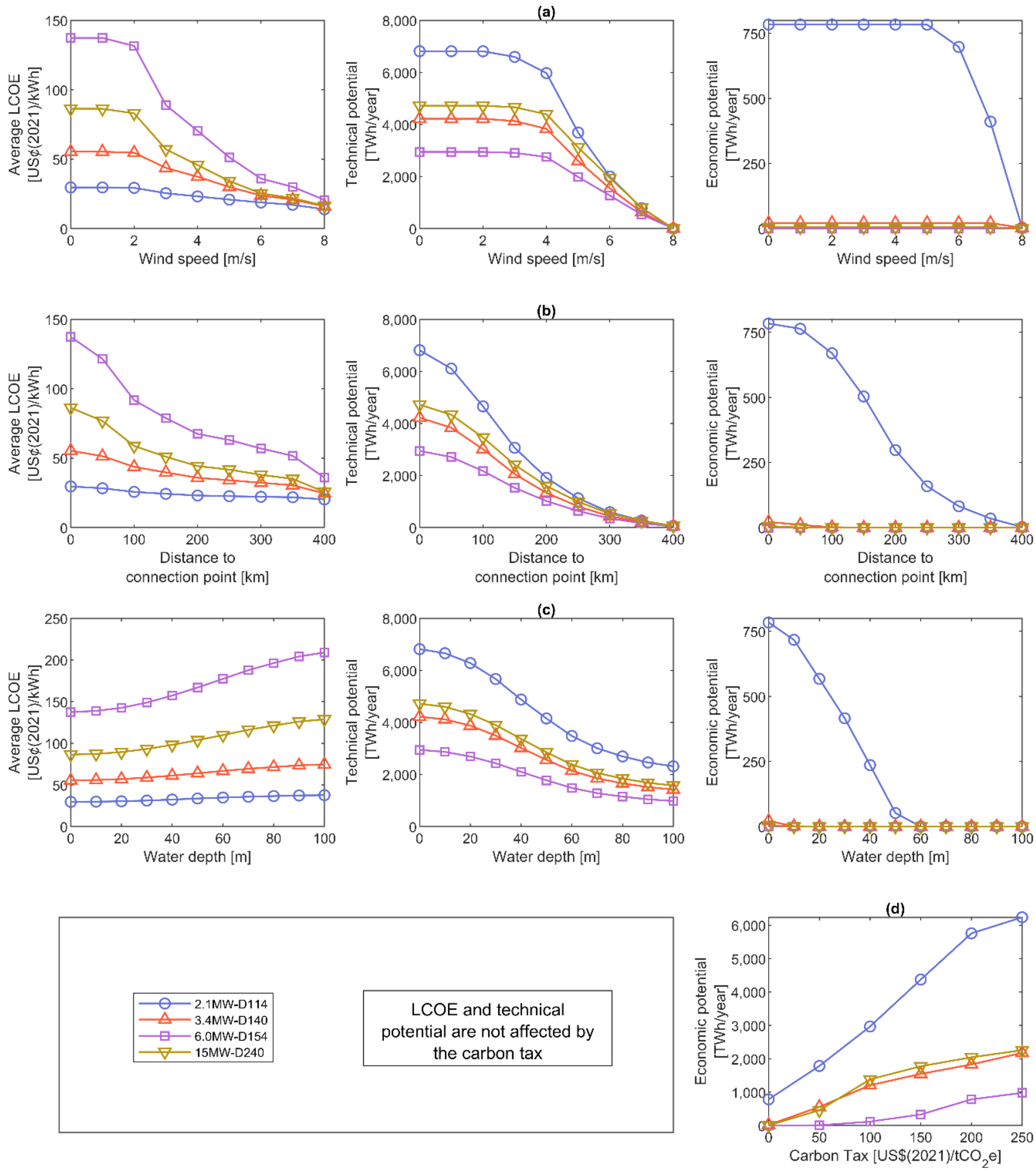


Figure 17. The sensitivity of average LCOE, technical potential, and economic potential per turbine based on minimum thresholds for (a) average wind speed, (b) distance to the onshore connection point, and (c) water depth. The x-axis in (c) is limited to 100 m to better show the graphs, especially at the transition from fixed-bottom to floating turbines at 55 m. Moreover, the impact of (d) a carbon tax on the economic potential per turbine is shown.

3.4. Sensitivity to wind farm and cost model parameters

In the previous sections, *2.1MW-D114* showed the best technical and economic performance, which is why this section solely focusses on this turbine. Figure 31 shows the sensitivity of our results to changes in six model parameters. The technical potential is the least sensitive with wind speed being the most impactful. Therefore, the robustness of the technical potential could be effectively increased with more accurate wind speed data from measurement and hindcast campaigns at selected areas and hub height. Such data could also validate the wind profiles of our study and offer a better understanding of the long-term wind characteristics. The hub height has a small impact on the technical potential and cost-related parameters none at all.

The economic potential is by far the most sensitive output. Especially the total efficiency (i.e. availability factor, transmission and wake losses) has a high impact, which shows that more detailed studies its components are necessary. Since such a study might not be computationally feasible for the entire country, our study could be useful to detect interesting sites suitable for a more localised analysis. The impact of the total efficiency could also indicate that even low-wind-speed, low-capacity wind turbines might have to be upsized eventually to decrease wake losses and to save costs from having less turbines within a wind farm.

Regarding CAPEX and discount rate, Figure 31 shows that mild offshore power could have a substantially higher economic potential when the technology is more developed. Technological learning could reduce CAPEX and investment risks with potentially positive impacts on interest rates for project finance. The OPEX has a relatively low impact on LCOE and economic potential, thus curbing the severity of OPEX-related limitations of our models. Nonetheless, given Indonesia's limited infrastructure for offshore wind projects today, future research should design and optimise possible O&M strategies considering infrastructure improvements. The economic potential barely changes with varying hub heights due to the neutralising effects of power production and tower costs.

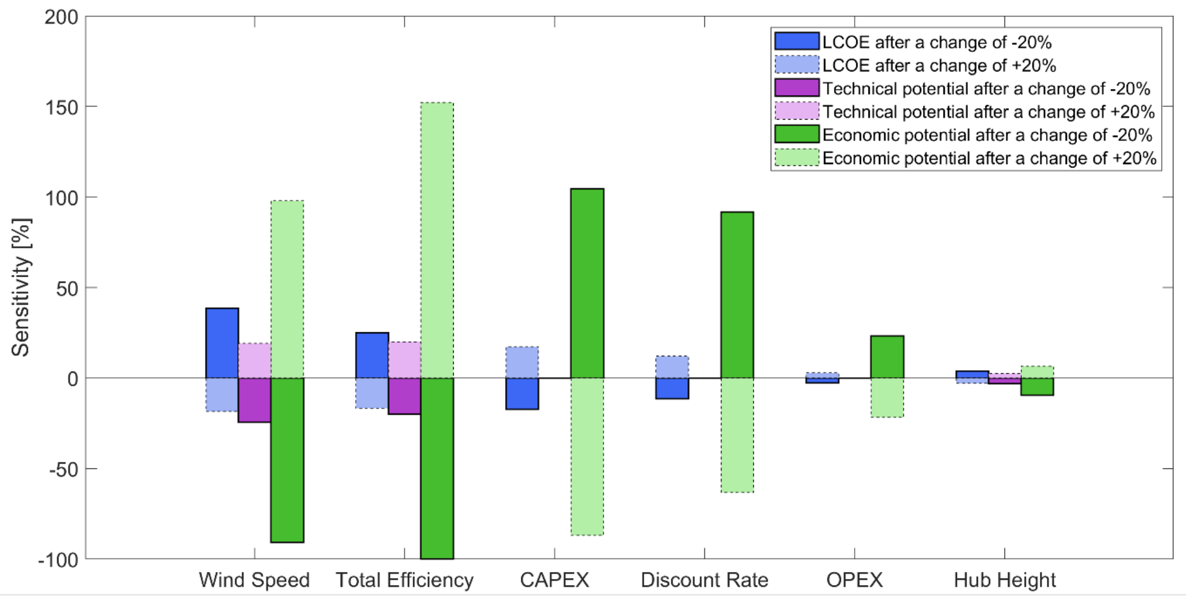


Figure 18. Sensitivity of average LCOE, technical potential, and economic potential of the 2.1MW-D114 to changes in model parameters by ±20%.

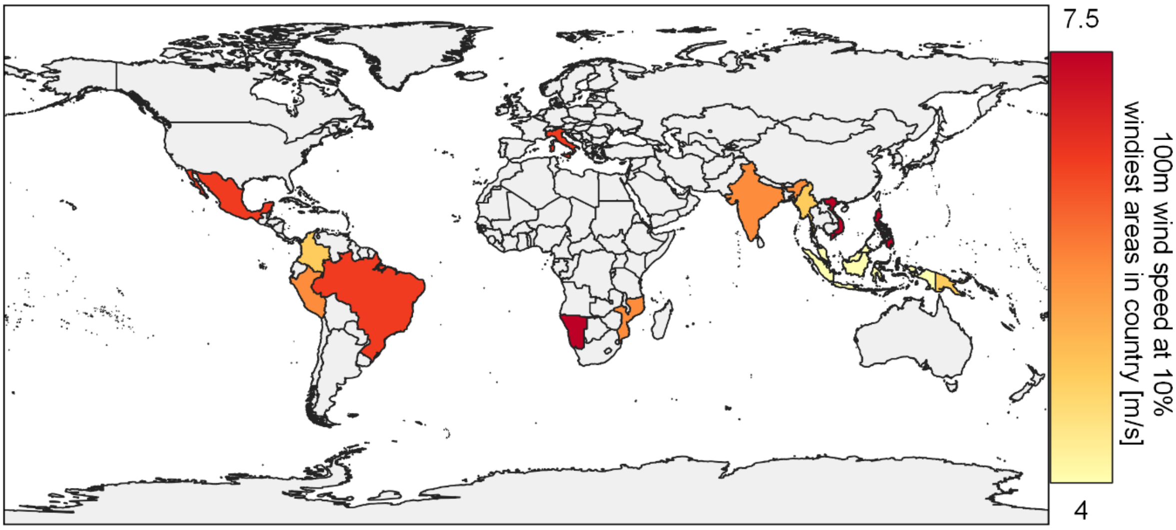
4. Conclusions

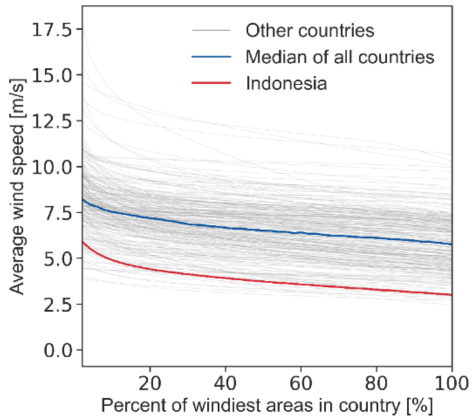
Here we show that low-wind-speed turbines are interesting for mild-resource regions like Indonesia. With a technical potential of up to 6,816 TWh/year, such turbines could perform substantially better in Indonesia than currently available and envisioned offshore turbines. Although low-wind-speed offshore turbines would not yet be competitive against existing wind farms in high-resource regions, they could still be attractive in regions with high electricity tariffs, like in rural Indonesia with an economic potential of 784 TWh/year. This insight holds a global relevance as much higher tariffs than in Indonesia can be found in parts of USA, Brazil, Australia, and India, amongst others [150]. Policy support, for example via a carbon tax of 150 US$(2021)/t$CO_2$e, would vastly extend the economic potential in Indonesia to 4,371 TWh/year to more developed regions with lower tariffs but much higher electricity demand.

However, low-wind-speed offshore turbines are not yet on the market, and need to be developed from scratch or by modifying existing low-wind-speed onshore turbines for offshore use. Such turbines could then be a highly interesting technology not only for Indonesia, but also for many other regions with mild wind resources, vast marine areas, and high electricity tariffs. As shown in Figure 19, not only South-East Asia could be an interesting hub for mild-resource wind power, but also South America with high-electricity-demand countries like Brazil, Mexico, Colombia, and Peru. Moreover, there might be vast potentials in India, where offshore wind could supply more than a billion people with electricity.

We conclude that mild offshore wind energy deserves more attention than it currently receives. With the industry's move toward larger turbines and higher wind speeds, offshore wind energy will gradually become a technology exclusively appropriate for regions with sufficiently high wind resources. However, successful climate change mitigation requires the rapid transition to climate-neutral electricity supply everywhere in the world. With low-wind-speed offshore turbines, manufacturers could tap a new market with a much broader potential user base, while decision makers would have another, previously inaccessible, option to decarbonise their energy systems.

To materialise these prospects, much still needs to happen. Given the sensitivity of our results, further research is necessary that validates our findings and further expands upon the methods we used. Future studies could focus on (1) improved modelling of wind farm spacing and wake losses, (2) more detailed operational expenses excluding site-specific strategies, (3) more detailed inclusion of local site conditions, (4) the assessment of dynamic cost developments from wind farm upsizing and technological learning, and using (5) higher fidelity wind datasets that reduce uncertainties associated with low-resolution data, such as not being able to capture rapid wind speed changes and thus leading to overestimation of the resource. With a better understanding of its potential, policy support could make low-wind-speed offshore power an attractive proposition for manufacturers, letting it grow from an unimportant niche to a regionally important piece of the global clean electricity puzzle.





Country	Wind speed at 10% windiest area [m/s]	Country	Wind speed at 10% windiest area [m/s]
Bahamas	7.5	Mozambique	6.4
Brazil	7.02	Myanmar	5.52
Colombia	5.85	Namibia	7.41
Cook Islands	7.11	Palau	5.21
India	6.58	Papua New Guinea	5.56
Indonesia	4.89	Peru	6.05
Italy	7.14	Philippines	7.45
Malaysia	4.11	Pitcairn	7.26
Maldives	4.72	Solomon Islands	5.78
Mexico	7.1	Tuvalu	5.39
Micronesia	6.3	Vietnam	7.21

Figure 19. Overview of 22 interesting countries for low-wind-speed offshore turbines. The countries were chosen based on a 100m wind speed at the 10% windiest sites [47] *of less than 7.5 m/s and an offshore EEZ area of at least 500,000 km². Nonetheless, there might also be high potentials in countries with smaller EEZ or mild-resource spots in otherwise high-resource regions. Note that the term "10% windiest sites" is adopted from GWA (ibid.), and refers to the 90th percentile of wind speeds in a country or region.*

4. The technical and economic potential of onshore wind

Abstract: Onshore wind potentials are commonly mapped with site selection criteria that either fully include or exclude land for wind farms. However, current research rarely addresses the variability of these criteria, possibly resulting in overly conservative or optimistic potentials. This chapter proposes a method to account for the variability of site selection criteria in resource assessments. We distinguish between static and flexible, non-binary criteria and assess onshore wind's technical and economic potential with bias-corrected ERA5 data, 28 power curves, and a turbine-specific cost model. For Indonesia, we show that our flexible mapping approach improves the transparency of resource potential assessments and could contribute to more informed and useful recommendations. These recommendations could address the (1) calibration of site exclusion thresholds, (2) dilemmas of preferring one land type over others, (3) location-specific challenges of wind farm deployment, and (4) more direct support schemes for affected stakeholders and wind farm operators. For Indonesia, we report a technical potential of 207–1,994 TWh/year, which could cover more than 50% of 2030 electricity demand on all islands. LCOEs range between 5.8–24.5 US¢(2021)/kWh with an economic potential of 16 TWh/year, which improves to 31–212 TWh/year with a carbon tax of 100 US$(2021)/t$CO_2$e.

Chapter 4: The technical and economic potential of onshore wind

This chapter was originally published as Langer, J., Zaaijer, M., Quist, J., Blok, K., 2023. Introducing site selection flexibility to technical and economic onshore wind potential assessments: New method with application to Indonesia. Renew. Energy 202, 320–335. https://doi.org/10.1016/j.renene.2022.11.084.

In the paper, we included the proximity to existing grid and road infrastructure as a site selection criteria for onshore wind farms, but not the costs of grid and road connection of the wind farms. For this dissertation, we added a box in section 3.3 that shows the impact of these cost components on the Levelised Cost of Electricity and economic potential.

Abbreviations, Symbols, and Indices

Abbreviation	Meaning
GIS	Geographic Information System
GWA	Global wind atlas
NREL	National Renewable Energy Laboratory

Symbol	Meaning	Unit (if applicable)
α	Shear exponent	-
η	Efficiency	%
a	Availability factor	%
A	Area	km^2
BPP	Biaya pokok penyediaan (basic costs of electricity provision)	US¢(2021)/ kWh
C	Wind farm correction factor	%
CAPEX	Capital expenses	US$(2021) million
CRF	Capital recovery factor	%
D	Rotor diameter	m
E	Electricity production	kWh/year
h	Hub height	m
H	Number of wind turbines inside wind farm area	-
i	Discount rate	%
LCOE	Levelised cost of electricity	US¢(2021)/ kWh
m	Mass	kg
N	Lifetime	Years
OPEX	Operational expenses	US$(2021) per year
P	Power	kW
S	Spacing factor between turbines	-
v	Wind speed	m/s
X	Correction factor	-

Index	Meaning (excluding cost components)
±20%	Variation by ±20% of reference value
100m	Hub height at 100 m
50m	Hub height at 50 m
a	Annual
c	Finely subdivided polygon
C	Number of finely subdivided polygons inside wind farm polygon
f	Factor
farm	Meshed wind farm polygon
lat	Latitudinal
long	Longitudinal
rated	Rated
t	Time step t
T	Total number of intervals (175,320 intervals over 20 years)
Wake	Wake losses of the wind farm

1. Introduction

The mapping of onshore wind power resources emerged as a popular research field with many studies published so far [209]. Like other renewables, onshore wind potentials can be mapped on a geographical, technical, and economic level [64] with gradually more restrictive site selection criteria that exclude unfavourable areas. Knowing about these resources and their location is important. Wind power has a great potential to decarbonise energy systems worldwide [209] but may compete against other land uses like forestry and urban development with its relatively large land footprint [210]. Therefore, available land must be allocated wisely to foster a socially just and acceptable energy transition [211].

The exclusion of unsuitable land is a well-established practice in resource assessment literature [209]. However, current studies mostly take on a binary approach, where certain areas are either fully included or excluded from analysis. Regarding the exclusion criteria, Ryberg et al. note that "there appears to be a lack of knowledge of the abstract geospatial qualities of these constraints, and […] how the application of one or more can impact the result of an [land eligibility] or similar analysis" [212, p.2]. However, Ryberg et al [212,213] address this shortcoming only in terms of land area, but not electricity production. Furthermore, McKenna et al. reviewed over 900 articles and reviews on onshore wind energy and found that "[m]ost often, the set of criteria and their buffers are chosen once" and that "up to now, most approaches for the geographical potential are more or less static" [209, p.664]. Out of the reviewed documents, they only found few studies that assessed the impact of exclusion layers further, e.g. via scenarios. We reviewed these studies [189,213–216] mentioned by McKenna et al. [209] and further papers [188,217,218] and, despite their relevance, found three limitations. First, the reviewed studies only report on the results per scenario, but not on the impact of individual land types causing the differences. Second, even if the potentials exceed the local electricity demand by a manifold, it remains unclear which types of land would be used to meet the demand and which stakeholders would be affected the most by the wind farms. Third, only one study [215] compared the costs of onshore wind against local electricity tariffs, but not per land type. Consequently, contemporary studies do not show which types of land play a key role in onshore wind power's development, whether there is enough available land per land type to meet future electricity demand, and whether there could be economic benefits and disadvantages from preferring certain land types for wind farm deployment over others.

Against this background, this chapter proposes a new method to include inconclusive, non-binary site selection criteria in resource assessment studies. The innovation of our study is the distinction between static and flexible site selection criteria for wind farm siting. Static criteria generally prohibit the deployment of onshore wind farms, like settlement areas. Flexible criteria apply to land which could be considered either via land transfer or co-existence, e.g. as forest-integrated wind farms. We demonstrate our method for Indonesia due to its strongly growing electricity demand and dependence on fossil fuels [9]. There, onshore wind is seen as unattractive by some [41,73,219], resource potential estimations are few [35,182,220], and none of these studies address the three limitations above. Therefore, we want to shed more light on Indonesia's wind resources and challenge the common belief that wind power is generally unattractive there.

We calculate the technical potential using 20 years of hourly bias-corrected ERA5 wind speed data and the power curves of 28 currently available wind turbines. The potentials are compared to the present and projected 2030 electricity demand. We calculate the *Levelised Cost of Electricity (LCOE)* using a turbine-specific cost model to determine the economic potential, which is the part of the technical potential with LCOE equal to or lower than the local electricity tariff. Moreover, we conduct a sensitivity analysis on technical and economic parameters.

The motivation of the study is to address the limitations detected by the leaders of the field and to showcase the usefulness of more flexible exclusion criteria for resource potential studies. Despite its regional focus, this work gains a global relevance as it addresses a general shortcoming in literature with methods that can be scaled to other case studies with global, publicly available datasets. Besides researchers, we target Indonesian policymakers and offer them a comprehensive overview of onshore wind's technical and economic potential, based on which wind power could be prioritised in national and regional energy transition strategies.

The chapter is structured as follows. Section 2 elaborates on the materials, methods and assumptions and their limitations. We report and discuss our results in section 3, and end with conclusions in section 4.

2. Materials and methods

In this section, we elaborate on the methods and assumptions to introduce site selection flexibility to wind potential assessments. We apply them to our case study of Indonesia as a running example to aid understanding. Nonetheless, we note that these methods can be applied at any desired, computationally feasible, regional scope.

2.1. Site selection with static and flexible criteria

First, the *Geographic Information System (GIS)* environment needs to be prepared, starting with a base map of the region's total land area and land use. Next, we distinguish between static and flexible exclusion criteria as shown in Table 13 for Indonesia. Static criteria generally prohibit the deployment of onshore wind power and respective areas are fully removed from the base map. The criteria are based on technical and economic limitations, like maximum elevation and slope, environmental barriers from wetlands and volcanoes, and social restrictions from built infrastructure. We use a settlement buffer of 500 m based on observations on google maps [221] (see Appendix D).

Table 13. Exclusion criteria for the mapping of onshore wind farm sites and open land layers. Unless stated otherwise, all thresholds and buffers are taken from the review by McKenna et al. [209], *and land use data for Indonesia from 2017 originates from* [222]. *The layer "Settlements" also contains former transmigration areas.*

Criterion Group	Exclusion layers	Layer type + Resolution	Threshold/ Buffer/ Remarks
Static exclusion criteria			
Orography	Slope [166]	Raster, 463 m	Slope ≥ 30° No buffer
	Elevation [166]	Raster, 463 m	Elevation ≥ 2,000 m No buffer
Water bodies/ wetlands	Water bodies	Vector	1,000 m
	Fish pond	Vector	1,000 m
	Swamp	Vector	1,000 m
	Swamp shrub	Vector	1,000 m
	Coastline	Vector	1,000 m
	Primary mangrove forest	Vector	1,000 m
	Secondary mangrove forest	Vector	1,000 m
	Primary swamp forest	Vector	1,000 m
	Secondary swamp forest	Vector	1,000 m
Natural catastrophes	Volcano [223]	Vector	1,000 m
Built-up infrastructure	Transmission lines	Line	250 m
	Settlements	Vector	500 m
	Airports/ harbours [224]	Point + Vector	2,000 m
Flexible stakeholder-related exclusion criteria			
Agriculture	Dryland agriculture	Vector	-
	Estate crop plantation	Vector	-
	Shrub-mixed dryland farm	Vector	-
	Rice field	Vector	-
	Mining	Vector	
Forestry	Plantation forest	Vector	-
	Primary dryland forest	Vector	-
	Secondary dryland forest	Vector	-
Rest	Nature conservation zones [225]	Vector	-
	Earthquake [223]	Vector	No high risk areas (own criterion)
	Landslide [223]	Vector	No high risk areas (own criterion)
Distance to built-up infrastructure	Substations [226]	Point	Within 10 km – ∞ (25–500 kV)
	Road [227]	Line	Minimum 0 – 500 m (classes: motorway, primary, secondary, service, tertiary, trunk, unclassified)
	Settlements	Vector	Minimum 500 – 2,000 m
Flexible site-property-related exclusion criteria			**Range**
Wind speed	Minimum wind speed	Vector	0 and maximum wind speed
Orography	Slope	Vector	0–30°
	Elevation	Vector	0–2,000 m
Remaining open land			
Open land	Bare land	Vector	-
	Bush/ shrub	Vector	-
	Savannah	Vector	-

Flexible exclusion criteria cover land that may be available after further scrutiny. The need for further assessment may stem from the (1) site's properties and their impact on the wind farm's technical and economic feasibility, or the (2) affected stakeholders and their acceptance to make land available for wind farm development. For the remainder of the chapter, we label these two groups as *site-property-related* and *stakeholder-related* criteria. Regarding (1), local site properties affect the feasibility of a wind farm, but the thresholds determining feasibility may be perceived differently per region and person, and may change with technological progress. Regarding (2), some land types may require a more intensive involvement of affected stakeholders during the wind farm development process to ensure social acceptance.

For clarity, and to prioritise assessment of sites with higher potential, we group land types as shown in Table 13 under “Open Land”, “Agriculture”, “Forestry”, and “Rest”.

We include conservation zones as some countries, like Indonesia [73], offer a legal basis to use them for renewable energy deployment. We are aware that this could be perceived as controversial given the social and cultural significance of these areas to local communities. Our intention is to show what would happen if these regulations would be maximally utilised, knowing that this might not be socially acceptable in practice.

Other stakeholder-related criteria may target project developers and investors, like distance to existing grid infrastructure (i.e. substations) and roads for site access. Expert consultation has indicated that a maximum distance to the electricity of 10 km is used in Indonesia. Therefore, we use this value as the most conservative threshold under practical project development conditions.

2.2. Integration of flexible site selection into geospatial analysis

After defining static and flexible site selection criteria above, we present our step-by-step approach in Figure 20 to integrate them in geospatial analyses. The steps are listed as follows:

1. Apply static exclusion criteria
2. Subdivide resulting wind farm polygon with a grid mesh
3. Subdivide by land type
4. Subdivide by wind speed class
5. Assign location-specific attributes to resulting polygons

After applying all static exclusion criteria in step 1, the resulting shapefile consists of thousands of polygons, each representing land (potentially) suitable for wind farms. We remove polygons smaller than 0.65 km^2 to curb computational efforts, which affected 0.08% of the otherwise suitable area. We acknowledge that the footprint of a single turbine is far smaller than the abovementioned threshold, so even those small areas could host individual turbines. Therefore, our potentials might be slightly too conservative.

Polygons are split along the province borders so that the technical and economic potentials can be attributed to individual provinces. Even then, polygons might stretch over thousands of square kilometres. Averaging properties like wind speed over such large areas might affect the resource assessment negatively, as local landscape details would be disregarded. Hence, we subdivide the wind farm polygons in step 2. We lay a 0.125°×0.125° grid mesh (about 14 km×14 km) over the wind farm shapefile and intersect the polygons with the mesh. From now on, these polygons are called *meshed polygons*. In steps 3 and 4, we subdivide these polygons further by the land groups listed in section 2.1 and wind speed using data from the *Global Wind Atlas (GWA)* [47]. For the latter, we clip the GWA raster to the wind farm polygons (after step 1), vectorise it, and group the wind speeds in steps of 1 m/s. The polygons obtained from step 4 are called *finely subdivided polygons* from now on.

After step 4, all wind farm areas consist of several finely subdivided polygons. In step 5, we add location-specific information to them. Besides average wind speed, elevation, and slope inside the polygon area, we also add the impact of varying buffers around substations (electricity grid), roads, and settlements as shown in Table 13. For the latter group, we create duplicate versions of the shapefile from step 4 and remove the areas that overlap with the different buffers. Then, the areas of the new resulting polygons are re-calculated and added as a new data column of the original shapefile.

After step 5, all finely subdivided polygons contain the following information:

- Island (group) and province in Indonesia
- Area of meshed and finely subdivided polygons in [km^2] for different buffers around substations, roads, and settlements
- Land type
- Mean GWA wind speeds at 100 m and 50 m hub height in [m/s]
- Mean elevation and slope in [m] and [°]
- Index of closest ERA5 point (see below)
- Local electricity tariff in [US¢(2021)/kWh] (see section 2.3.3)

One of the attributed is the index of the closest ERA5 point containing 20 years of hourly local wind speed data at 100 m height. We use ERA5 wind speed data to calculate the electricity production of the wind farms. By itself, ERA5 does not yet reflect the detailed local orography given its coarse spatial resolution of 0.25°×0.25° (28km×28km). Therefore, we complement the ERA5 data with GWA data, which provides average, high-resolution wind speed data (250m×250m). The abovementioned ERA5 index determines which wind profile from the ERA5 dataset should be used per finely subdivided polygon. Then, we compare the average wind speed of the ERA5 wind profile with the mean GWA wind speed assigned in step 5. As done in [158,228–231], we compute a time-invariant, constant correction factor from the difference between ERA5 and GWA. The ERA5 profile is then multiplied with the correction factor to match the GWA value. Recent studies indicate that correction factors are close to unity (between 0.8–1.2) in far-offshore regions but tend to be higher in (1) near-shore areas due to the complexity at the land-sea interface with factors above 2 [232], and in (2) mountainous terrain with factors above 3 [228]. Such high correction factors might lead to strongly fluctuating wind profiles with large amplitudes. Therefore, we assess what causes high correction factors and whether they lead to disproportional wind speeds. In this study, wind speeds are considered disproportional if they exceed the 50-year return gust of the IEC wind class [233]. For example, if a polygon is situated at a IEC class III location (i.e. with average speeds of up to 7.5 m/s), wind speeds above 52.5 m/s are considered disproportional.

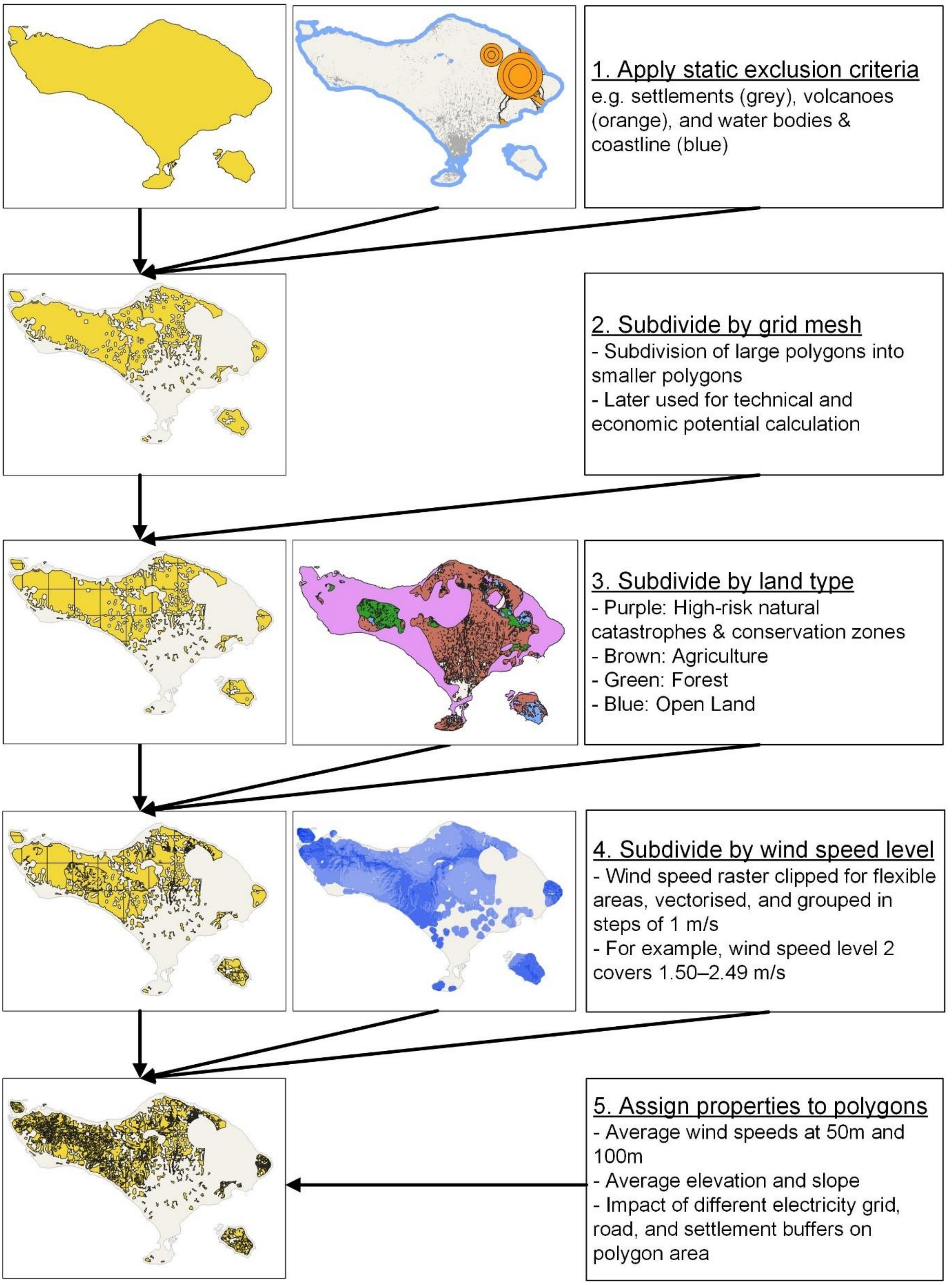


Figure 20. Overview of polygon subdivision as demonstrated for Bali, Indonesia, as an example. The result is a shapefile that contains all areas suitable for onshore wind, their site properties, and distinguishes between different land uses and wind speed levels. This chapter mainly reports and discusses the results per meshed polygons (after step 2) and per finely subdivided polygons (after step 5).

2.3. Technical and economic analysis of onshore wind power

2.3.1. Technical onshore wind potential

The technical onshore wind potential is the aggregated annual electricity production E_a of the wind farms deployed over all suitable areas. We calculate E_a for each finely subdivided polygon with Eq. (1) using turbine-specific power curves *P(v),* the number of wind turbines *H* inside each polygon, and constant values for wake efficiency η_{Wake} and availability factor a_f (88% and 97%, respectively [23]). With Eq. (1), we calculate the average net electricity production in MWh/year in a computationally inexpensive way. Nevertheless, a shortcoming is the omission of annual fluctuations of electricity generation, which in practice could affect the wind farms' bankability, e.g. for loan repayment [234].

$$E_{a,c} = \frac{\sum_{t=1}^{T} P(v_{c,t})}{T} * H_c * \eta_{Wake} * a_f * 8{,}760 \frac{hours}{year} \tag{1}$$

Variables	Indices
η: efficiency	*a:* annual
a: availability	*c:* finely subdivided polygon
E: electricity production	*f:* factor
H: number of turbines in a polygon (see Eq. (2))	*t:* time step (hourly)
P: power output of single turbine	*T:* total number of intervals (175,320 intervals over 20 years)
v: wind speed	*Wake*: wake effects of the wind farm

We use the power curves *P(v)* of 28 turbine models (see Appendix E) from The Wind Power [153] database. We select the wind turbines based on four criteria, namely (1) rated power ≥ 1,500 kW, (2) cut-in wind speed ≤ 3 m/s, (3), rated wind speed ≤ 12 m/s, and (4) current availability on the global market (as of February 2022). We also include the two turbine models deployed in Indonesia's only two existing wind farms, Sidrap and Jeneponto, which otherwise would have been excluded for not being available anymore (Sidrap) and a too high rated wind speed (Jeneponto). We present and discuss the results not per turbine, but as median values and 25th and 75th percentiles.

We compute the number of turbines inside a polygon *H* with Eq. (2) as a function of polygon area *A*, rotor diameter *D*, and dimensionless turbine spacing factor S (*5D×10D* [23]). Initially, *H* is calculated for the finely subdivided polygons, which can lead to *H < 1*, i.e. less than one full turbine. This is to be expected, as the subdivided polygons merely represent a fraction of the entire wind farm area obtained from step 1. The sum of all *H* would be a float, although in practice it needs to be an integer. Therefore, we calculate a correction factor *C* with Eq. (3), which uses a floor function to ensure that all *H* of finely subdivided polygons inside a meshed polygon add up to an integer.

$$H_c = \frac{A_c}{S_{long} * D * S_{lat} * D} * C_{farm} \quad (2)$$

$$C_{farm} = \frac{\left\lfloor \frac{\sum_{c=1}^{C} A_c}{S_{long} * D * S_{lat} * D} \right\rfloor}{\frac{\sum_{c=1}^{C} A_c}{S_{long} * D * S_{lat} * D}} \quad (3)$$

Variables	**Indices**
A: area of wind farm	*a:* annual
C: correction factor	*c:* finely subdivided polygon
D: rotor diameter	*C:* Number of finely subdivided polygons inside meshed polygon
H: number of turbines in a polygon	*farm:* meshed wind farm polygon
S: dimensionless spacing between turbines in a wind farm	*lat:* latitudinal
	long: longitudinal

One limitation of our approach is the use of time- and space-invariant constants for turbine spacing, wake efficiency η_{Wake}, and availability factor a_f as found in literature [158,209]. It was computationally infeasible to model these parameters for more than 700,000 finely subdivided polygons and 20 years of hourly resource data. The wind farms in Indonesia can have a far denser turbine spacing than *5D×10D* as seen in Appendix D. But since we could not check the corresponding wake losses at these wind farms, we use a matching spacing *S* and wake efficiency η_{Wake} from literature [23]. Another limitation is that we omit the effects of air density on the turbine power curves, which might be significant in locations with higher altitudes.

Later, we evaluate the accuracy of our simulated power production profiles with Indonesian wind power statistics [235]. As of February 2022, there are two wind farms in Indonesia, Sidrap and Jeneponto [171]. A full year of wind power production from both wind farms is available for the year 2020. For that year, we compare the recorded electricity production with the simulated production of the uncorrected and corrected ERA5 wind profiles. A sample of two wind farms and one production year is far too small to make a final statement about the accuracy of our production profiles. Moreover, we would have preferred to use real-life hourly production data for bias correction via a measure-correlate-predict approach [170]. However, such data is not publicly available for Indonesia's existing wind farms.

To put the technical and economic potentials into perspective, we compare them to the present and future electricity demand. For Indonesia, we use the (expected) electricity generation in 2018 [1] and 2030 [9], respectively. We group Indonesia's 34 provinces (as of February 2022) in "Sumatera", "Java & Bali", "Kalimantan", "Sulawesi", and "Nusa Tenggara, Maluku, and Papua", which is in line with the practices of the country's state utility company [9]. The electricity generation is then aggregated per island group and compared with the calculated electricity generation of our onshore wind farms.

2.3.2. Levelised cost of electricity and turbine-specific cost model

For the economic analysis, we calculate the *Levelised Cost of Electricity (LCOE),* which indicates the electricity tariff needed to break even with all project costs at the end of the project's useful lifetime and is calculated with Eqs. (4) and (5), assuming a discount rate *i* of 10% [66,178] and a lifetime *N* of 20 years [158]. The project costs consist of *Capital Expenses (CAPEX)* and *Operational Expenses (OPEX)* as elaborated below.

$$LCOE_{farm} = \frac{CRF * CAPEX_{farm} + OPEX_{farm}}{E_{a,farm}} \tag{4}$$

$$with\ CRF = \frac{i * (1+i)^N}{(1+i)^N - 1} \tag{5}$$

Variables
CAPEX: capital expenses
CRF: capital recovery factor
E: electricity production
i: discount rate
N: lifetime
OPEX: operational expenses

Indices
a: annual
farm: wind farm (polygon after step 1 in Figure 20)

We use the mass-based cost model developed by the *National Renewable Energy Laboratory (NREL)* [187] to calculate CAPEX and OPEX. We calibrate the cost model with updated component costs and technology-specific correction factors derived from the most recent cost review report by NREL [174]. The component cost functions and correction factors are listed in Appendix C. We check the cost model by comparing the calculated CAPEX with the investment costs of the wind farms Sidrap and Jeneponto in Indonesia. Unless stated otherwise, all costs are converted to US$(2021) using the currency conversion rates listed in Appendix B [236,237].

The cost model and surrounding assumptions come with three limitations. First, we did not consider land type specific cost components, like compensation payments to farmers. Second, we did not include system integration costs covering grid connection and management. Third, we do not consider cost developments from economies of scale and technological learning as two wind farms are too few to make tangible statements about the latter's effects on wind farm costs in Indonesia. However, we recommend the consideration of the abovementioned aspects in future research once wind power progressed further in Indonesia.

2.3.3. Economic onshore wind potential with and without carbon tax

The LCOE itself is already useful for comparing onshore wind's economic performance against other power generation technologies. However, it does not reveal the economic feasibility against the local electricity tariff. In Indonesia, the receivable tariff is based on and capped by the *Biaya Pokok Penyediaan (BPP – Basic cost of electricity provision)*. Based on a simplification of regulation MEMR Nr. 169/2021 [198], we assume that all wind farms receive 85% of the regional BPP, resulting in a tariff range of 5.37–16.59 US¢(2021)/kWh.

With these tariffs, it is possible to calculate the economic onshore wind potential. The economic potential is the part of the technical potential for which *LCOE* ≤ local electricity tariff. We want to stress that the receivable tariffs may differ in practice from the tariffs assumed here since we use cap values. Moreover, renewable energy support schemes frequently change in Indonesia [54], so it is unclear how renewable energy producers will be remunerated in the future.

One criticism of the current BPP-based scheme is that external costs from pollution are not considered [238]. Therefore, we investigate the impact of a carbon tax on the economic onshore wind potential. We calculated the electricity tariffs with carbon tax via the back-of-the-envelope calculation in Supplementary File 1 based on general emission factors [12] and the 2018 primary energy consumption and generation mix in Indonesia [239].

2.4. Sensitivity analysis

To address the limitations elaborated in section 2.3, we conduct a sensitivity analysis to understand their impact on the results better. We vary the CAPEX, OPEX, discount rate, wind speed, hub height, and BPP by ±20% to show the change of median LCOE, technical potential, and economic potential. For the hub height *h*, the wind speed *v* is adjusted with Eqs. (6) and (7). The local shear exponent α is calculated with GWA data at 50 and 100 m height [177].

$$v_{\pm 20\%,c,t} = v_{100m,c,t} * \left(\frac{h_{\pm 20\%}}{h_{100m}}\right)^{\alpha_c} \tag{6}$$

$$\alpha_c = \frac{\ln\left(\frac{v_{100m,c}}{v_{50m,c}}\right)}{\ln\left(\frac{h_{100m}}{h_{50m}}\right)} \tag{7}$$

Variables
α: shear exponent
h: height
v: wind speed

Indices
±20%: variation by ±20%
50m: hub height at 50 m
100m: hub height at 100 m
c: finely subdivided polygon
t: time step (hourly)

3. Results and discussion

3.1. Evaluation of bias-correction factors and cost model

Before presenting the results of the technical and economic analysis, we assess the bias-correction factors, their impact on the wind profiles, and the accuracy of our wind farm and cost model. Figure 21 shows the impact of elevation, slope and GWA wind speeds on the bias-correction factors across Indonesia.

Three insights can be drawn from Figure 21. First, most correction factors are above 1, indicating that ERA5 mostly underestimates wind speeds on land compared to GWA data. Second, a more detailed subdivision of suitable wind farm areas enables a more comprehensive analysis of local site conditions. For example, the maximum averaged GWA wind speed in Indonesia increases from 9.7 m/s to 12.6 m/s if polygons are finely subdivided. Third, due to the more detailed representation of local site conditions, correction factors tend to increase with further subdivision, with the maximum correction factor increasing from 5.6 to 7.2.

These insights show that ERA5, as well as other reanalysis datasets, cannot fully capture the local orography and its impact on local wind resources. This is in line with Gruber et al. [228], who found high correction factors above 2 in mountainous terrain in Brazil, USA, South Africa, and New Zealand. Indonesia's complex, archipelagic geography might be a reason why our correction factors are higher. Then again, factors above 5 are exceptional even for Indonesia, as more than 95% of our factors range between 0.33–3.

The correction factors presented above mostly do not lead to disproportional wind speeds as per our definition in section 2.2. Only 84 polygons (or 0.01% of all finely subdivided polygons) showed peak wind speeds higher than the 50-year return gust of the IEC wind class to which the site belongs. Their correction factors range between 1.3–3.4 and almost all of them are on East Java, indicating that the ERA5 profile there already contains unusual spikes. The bias-corrected peak wind speeds rarely exceed 30 m/s (see Figure 22), even for extreme correction factors above 5.

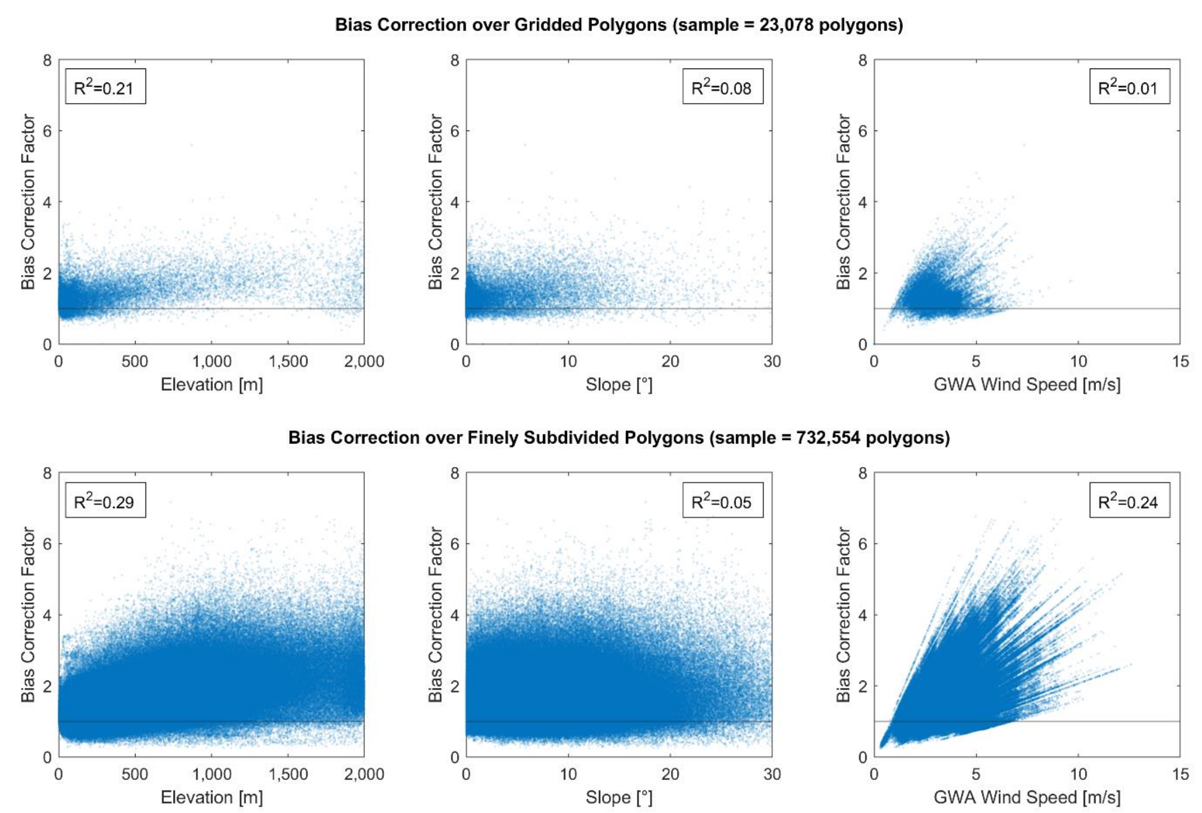


Figure 21. Impact of elevation, slope, and average GWA wind speed on bias-correction factors for meshed and finely subdivided polygon (i.e. the polygons obtained from step 2 and 4 in Figure 20, respectively).

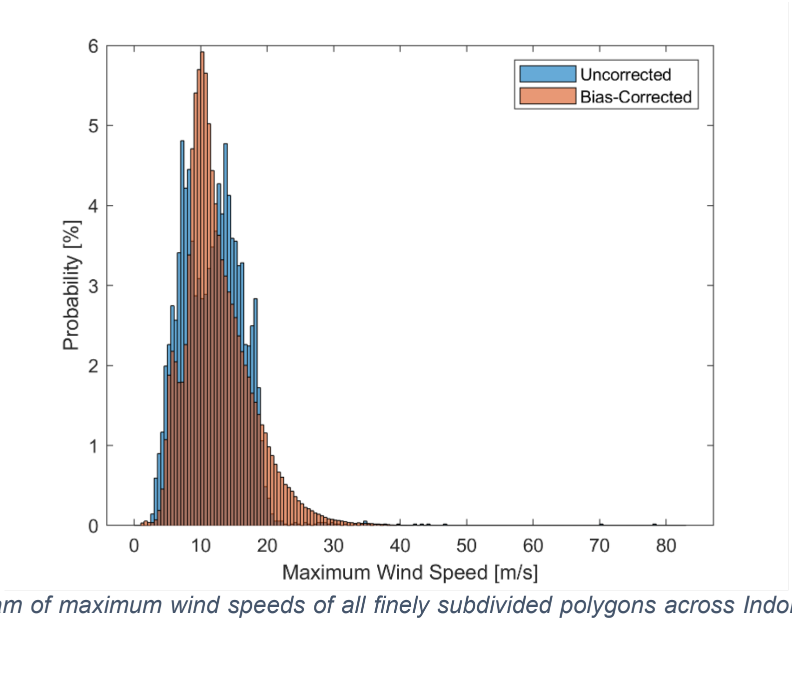


Figure 22. Histogram of maximum wind speeds of all finely subdivided polygons across Indonesia (sample size: 732,554 polygons).

Table 14 shows a comparison of recorded and calculated electricity generation with and without bias correction. Bias correction significantly improves the accuracy of electricity generation estimations, from a deviation of –62% without correction to +4% with bias correction. This underlines that re-analysis data should not be used for electricity production estimations without prior bias correction, especially for onshore sites in complex terrain.

Table 14. Comparison of calculated electricity generation values with the recorded generation of Indonesia's two wind farms Jeneponto and Sidrap. For the original CAPEX of Jeneponto, we assume US$(2017) based on the start of construction [240].

		Sidrap	**Jeneponto**
Coordinates		119.71° E 3.99 °S	119.76° E 5.65 °S
Size [MW]		75 MW	72 MW
Number of turbines		30	20
Hub height [m]		80	133
Rotor diameter		114	130
Average 100m wind speed [m/s]	GWA	7.18	6.16
	ERA5	3.21	4.91
Correction factor		2.24	1.26
Start of commercial operation		5th April 2018	14th May 2019
Actual CAPEX [US$ (2017) million]		150	160
Actual CAPEX [US$ (2021) million]		162	173
Calculated CAPEX [US$ (2021) million] and deviation [%]		97 (–40%)	106 (–39%)
Recorded electricity generation 2020 [GWh]		473	
Calculated electricity generation 2020 [GWh] and deviation [%]	Uncorrected	181 (–62%)	
	Bias-corrected	494 (+4%)	

Our CAPEX estimations in Table 14 are roughly 40% lower than the reported investment costs [241,242]. The cost model and calibration data originate from the US [174,187], so the different development stages of onshore wind in the USA and Indonesia could explain the deviations. In the USA, wind power is a mature technology with 118 GW of installed capacity in 2021 [243], while Sidrap and Jeneponto are the first two large wind farms in Indonesia. These wind farms might be more expensive due to first-of-its-kind costs, and hence not representative once wind power progresses further. Therefore, we continue to use the cost model with the US data to provide an outlook to onshore wind's future economic potential in Indonesia.

3.2. The technical potential and impact of static and flexible site selection criteria

In this section, we report and discuss the technical onshore wind potential in Indonesia and the impact of static and flexible site selection criteria. Figure 23 reveals that flexible criteria can help determining suitable thresholds for site exclusion. Most notably, the technical potential already declines sharply at a minimum average wind speed of 2 m/s. In literature, more stringent thresholds at 4.5 m/s and higher are used due to economic infeasibility [244,245]. From a technical perspective, such thresholds may exclude considerable resources from further analysis, in Figure 23(a) almost 1,500 TWh/year. These resources might become economically feasible if low-wind-speed turbines are further developed and their costs gradually decline. The static elevation and slope thresholds of 2,000 m and 30° from Table 13 seem adequate and do not exclude noticeable technical resources.

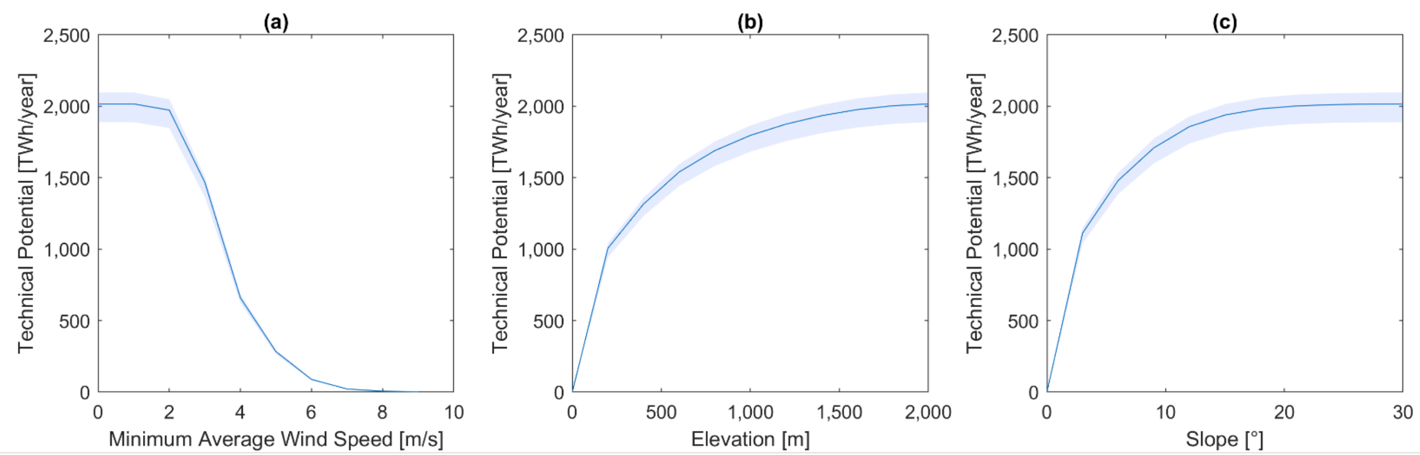


Figure 23. Impact of (a) minimum average wind speed at hub height, (b) maximum elevation, and (c) maximum slope on the technical onshore wind potential (blue line: median, light-blue field: 25th–75th percentile).

If only static criteria are used, 63.6% of Indonesia's land area would be suitable for onshore wind as shown in Table 15. The most limiting static criterion are wetlands given Indonesia's vast mangrove and swamp forests as well as more than 50,000 km of coastline [246]. Moreover, Table 15 not only demonstrates the impact of flexible criteria, but also how their selection affects the results. For example, if conservative thresholds from literature [209] and practice in Indonesia apply, the share of suitable land declines drastically to 0.08%. However, the resulting potentials may be overly conservative as seen for a maximum distance to the next substation of 10 km. This threshold may reflect the practical perspective of Indonesia's state utility company, project developers, and lending institutions, but it also disregards the possible extension of the public grid and off-grid solutions, which could make the removed sites feasible again. Therefore, a critical assessment of exclusion criteria and their development over time may yield more than a snapshot of renewable resources.

Table 15. Impact of exclusion criteria on land availability and technical potential. The percentage of excluded area is based on the total Indonesian land area of 1,890,077 km². The range of excluded technical potential is based on the capacity densities of 2.9–5.3 MW/km² in Appendix E. The excluded area and technical potential of the individual criteria do not add up to the total excluded land because some criteria overlap.

Exclusion group	Excluded area [10^3 km²]	Percentage of total area excluded [%]	Technical potential excluded [GW]
Static criteria			
Maximum slope and elevation	50	3%	147–266
Water bodies/ wetlands	515	27%	1,493–2,729
Volcanoes	36	2%	80–146
Built infrastructure	144	8%	418–764
Total excluded static land (before excluding flexible land)	687	36%	1,993–3,642
Stakeholder-related criteria			
Nature conservation	226	12%	659–1,195
Agriculture & Mining	583	31%	1,692–3,092
Forestry	797	42%	2,319–4,208
Natural-catastrophe-prone areas	351	19%	1,018–1,861
Site-property-related criteria			
Minimum average 100m wind speed (0–2–4 m/s)	0–282–1,654	0–15–88%	0–8,766
Distance from settlements (0.5–1–2 km)	128–203–331	7–11–17%	370–1,752
Minimum distance from roads (0–250–500 m)	0–243–410	0–13–22%	0–2,176
Proximity to substation (∞–100–10km)	0–118–1,674	0–6–89%	0–8,872
Total excluded static and flexible land	**1,771–1,782–1,889**	**93.7–94.3–99.9**	**9,386–10,012**

Furthermore, flexible site selection criteria could provide a more useful and transparent set of options for decision makers to allocate renewable capacity. In Table 16, Indonesia's median technical onshore wind potential ranges between 207–1,994 TWh/year depending on the available land types. Both sides of the range come with benefits and limitations.

The lower end limits onshore wind to open land, which might improve the social acceptance of the technology as no land is transferred from agriculture and forestry, and conservation zones remain unaffected. But again, this option might be overly conservative, as wind farms can be integrated into forests and agricultural land for shared use. Such integrated solutions could be especially interesting for islands where open land is scarce, like Java and Bali. Moreover, some farmers and forest owners might be willing to share or even sell their land. Regarding earthquake risk, wind farms can be designed to withstand seismic stresses, e.g. by following DNV's recommended practice [247].

Table 16. Available land, technical potential, and share of present and future electricity demand of onshore wind power per island (group) in Indonesia depending on whether all land types or only open land are used. For distance to settlements, roads, and electricity grid, we assume the most lenient thresholds, i.e. 500 m to settlements, 0 m to roads, and no maximum distance to the next substation. Note that all island groups combined represent Indonesia as a country.

Island (Group)	Max available land for onshore wind [km^2]	Percentage of total local land area [%]	Median technical potential [TWh/year]	Coverage of (projected) demand in 2018 and 2030 [times]	
All land types considered					
Sumatera	309,633	65.0%	509	12	6.0
Java + Bali	64,371	46.6%	223	1.1	0.8
Kalimantan	372,390	69.6%	408	35	15
Sulawesi	139,718	75.3%	241	21	10
Nusa Tenggara, Maluku, and Papua	316,623	57.1%	613	102	38
Indonesia	**1,202,735**	**63.6%**	**1,994**	**7.2**	**4.5**
Only open land					
Sumatera	26,193	5.5%	45.5	1.1	0.5
Java + Bali	502	0.4%	1.8	0.009	0.006
Kalimantan	61,259	11.4%	74.9	6.5	2.8
Sulawesi	12,476	6.7%	25.1	2.1	1.0
Nusa Tenggara, Maluku, and Papua	18,423	3.3%	60.6	10.1	3.8
Indonesia	**118,851**	**6.3%**	**207.2**	**0.7**	**0.5**

The upper end of the potential assumes that all flexible land is considered for wind farms, which boosts onshore wind's impact for Indonesia's energy transition but might also create fierce social resistance. Furthermore, too optimistic resource potentials may raise skewed expectations about their practical feasibility. Only 2.2% of all finely subdivided polygons have a median capacity factor above the global wind industry's average of 34% [199], with values above 40% mainly in South Sulawesi, Maluku, and East Nusa Tenggara. In contrast, more than 70% of the polygons have capacity factors below 10%. Lastly, the potentials do not reflect the actual regional electricity demand. For example, a technical onshore wind potential of up to 613 TWh/year in Nusa Tenggara, Maluku, and Papua is opposed by an expected combined 2030 demand of 16 TWh [9]. Even without considering the economics of onshore wind there, only a small fraction of the technical potential can be materialised in practice, unless the local demand exceeds current expectations significantly.

With these contemplations, more specific energy transition goals could be proposed with more adequate support schemes for affected stakeholders. Figure 24 shows the electricity demand coverage and land use of onshore wind for Indonesia and its island groups. In one case, we only use open land; in the other we use all land types ranked by average 100m wind speed. Considering all land types, onshore wind could supply 100% of regional 2030 electricity demand everywhere except for Java and Bali, where 50% of demand could be covered.

Figure 24 illustrates the drawbacks of only considering open land for wind farm deployment, as more land is required to produce the same amount of electricity. Considering the subsequent surplus cost, this insight harmonises with Wehrle et al. [248], who found that leaving landscapes undisturbed could lead to considerable opportunity cost. Furthermore, our findings may raise a moral question about what is preferred: to use open, less socially controversial land with suboptimal wind resources and thus higher land requirements, or to resort to used and conserved land with better wind resources and lower environmental impact from land conversion, but with potentially negative implications for local communities and wildlife? Although we cannot provide an answer to this complex question here, we believe that flexible site selection may at least create an awareness of such dilemmas.

However, flexible site selection also reveals the local challenges of onshore wind from built infrastructure and a lack thereof, as shown in Figure 25. Urbanised islands like Java and Bali have an extended electricity grid, but also a dense network of roads and settlements. Thus, onshore wind's potential decreases significantly if a minimum distance from roads and settlements is introduced. The proximity to substations is less impactful in Java and Bali compared to other islands, but still significant with a reduction to roughly 20% of the original technical potential with a maximum distance to substation of 10 km.

On the one hand, distance to roads and settlements is far less impactful on rural, less-developed islands. On the other hand, proximity to existing grid infrastructure wipes out most of the otherwise available technical potential, e.g. to as little as 2% of the original potential on Nusa Tenggara, Maluku, and Papua. These observations underline that there is no one-size-fits-all solution for the energy transition. On islands like Java and Bali, renewables that can be integrated into urban infrastructure, like rooftop solar PV, might be preferable over onshore wind, which could take a complimentary role at less built-up sites. On rural, less-connected islands, considerable investments in electricity grid and road infrastructure would be required to materialise the abovementioned potentials. Especially in East Indonesia, many wind farm sites are situated hundreds of kilometres from the next substation, e.g. on remote islands. There, a solution could be small-scale wind farms integrated via micro-grid systems.

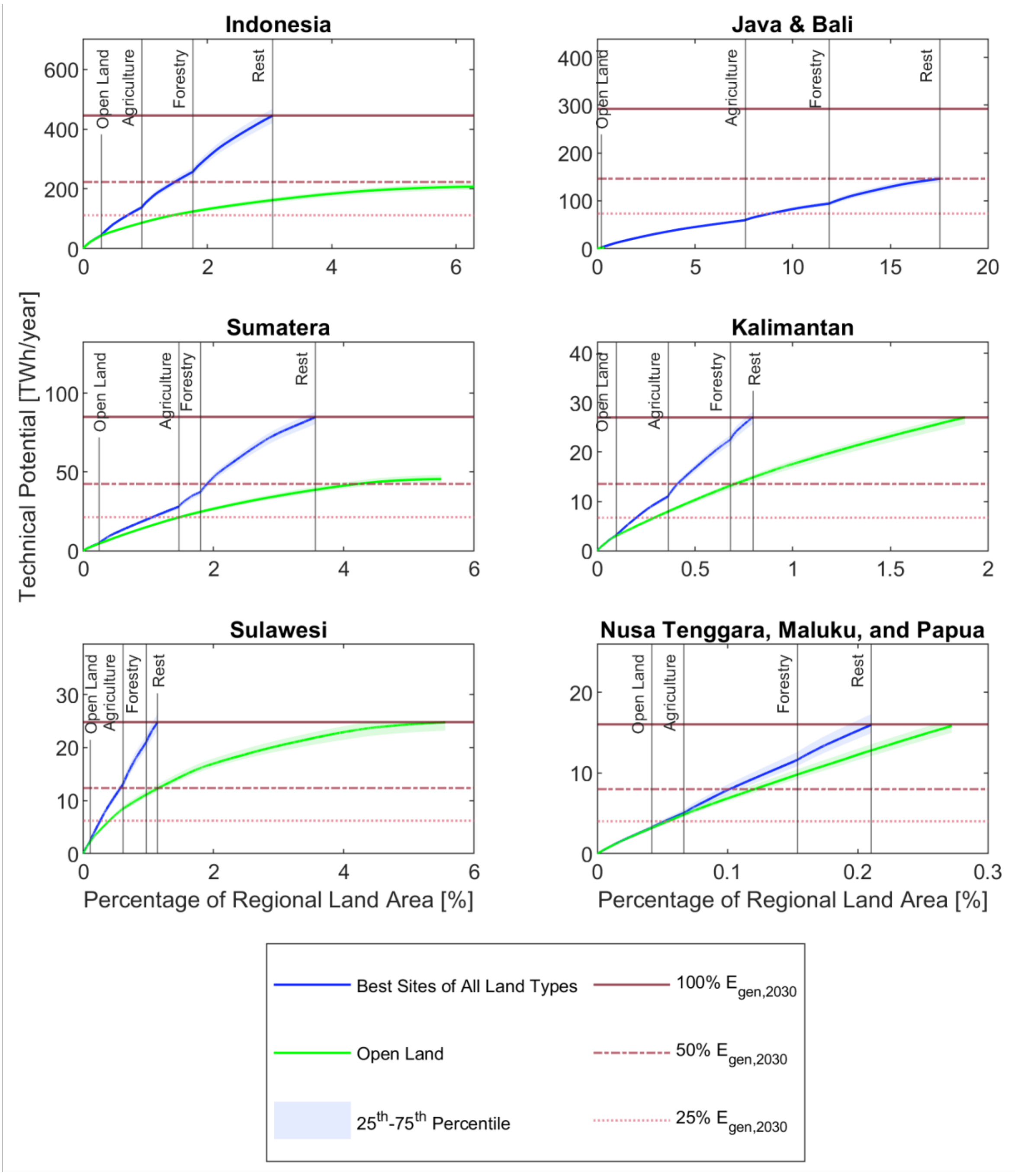


Figure 24. Land area and land type requirements to meet 100% electricity demand in 2030 for Indonesia and its island groups. For Java & Bali, 50% demand coverage is illustrated as there are not sufficient resources to cover the entire demand. Annual electricity production from onshore wind and percentage of used land area and type in Indonesia and per island (group). The sites are ranked by 100m wind speed to ensure that technically favourable sites are selected for demand coverage. Mining areas are included in "Agriculture". "Rest" refers to conservation zones and areas with high risk of earthquakes or landslides. The labels of the x- and y-axes apply to all subplots. Note that the land impact shown here refers to the area spanned by the wind farms. The footprint of the individual turbines (e.g. turbine tower) is much smaller.

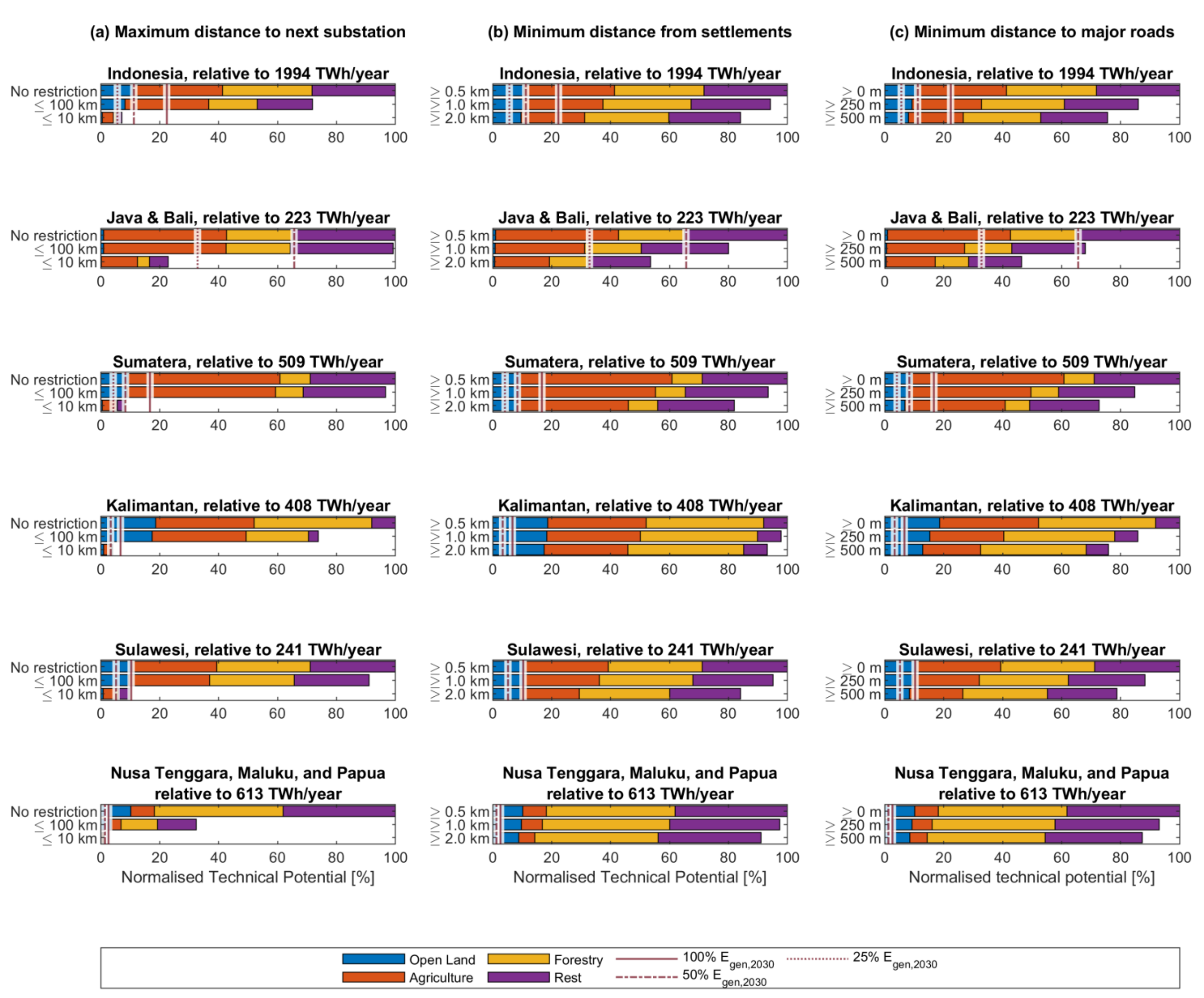


Figure 25. Impact of distance to the (a) closest substation, (b) settlements, and (c) roads on the median technical onshore wind potential on different land types in Indonesia and per island (group). Mining areas are included in "Agriculture". "Rest" refers to conservation zones and areas with high risk of earthquakes or landslides. The labels of the x-axis apply to all subplots.

3.3. The economic potential of onshore wind power

In this section, we discuss the economic onshore wind potential in Indonesia, influence of flexible site selection criteria, and impact of a carbon tax. We start with the LCOE, which we calculate per meshed wind farm polygon.

Figure 26 shows the usefulness of minimum wind speed thresholds when mapping economic wind resources, but also potential pitfalls currently unaddressed in literature. There is an exponential relationship between LCOE and wind speed, and 4 m/s appears to be a reasonable threshold beyond which LCOE might reach competitive levels. At average wind speeds between 4–10 m/s, the LCOEs range between 5.8–24.5 US¢(2021)/kWh. The lower end of the range is on par with the industry's average of 6 US¢(2018)/kWh [199], and shows that Indonesia could produce cheap renewable electricity if costs reach current US levels. However, Figure 26 shows the complexity of choosing the "right" threshold. If too low, uneconomic sites are not filtered out and thus potentially lead to an overestimation of economic potential. If too high, economic sites may be excluded and the economic potential becomes too conservative. This dilemma underlines the benefits of flexible site selection criteria, as thresholds be determined transparently and evaluated critically.

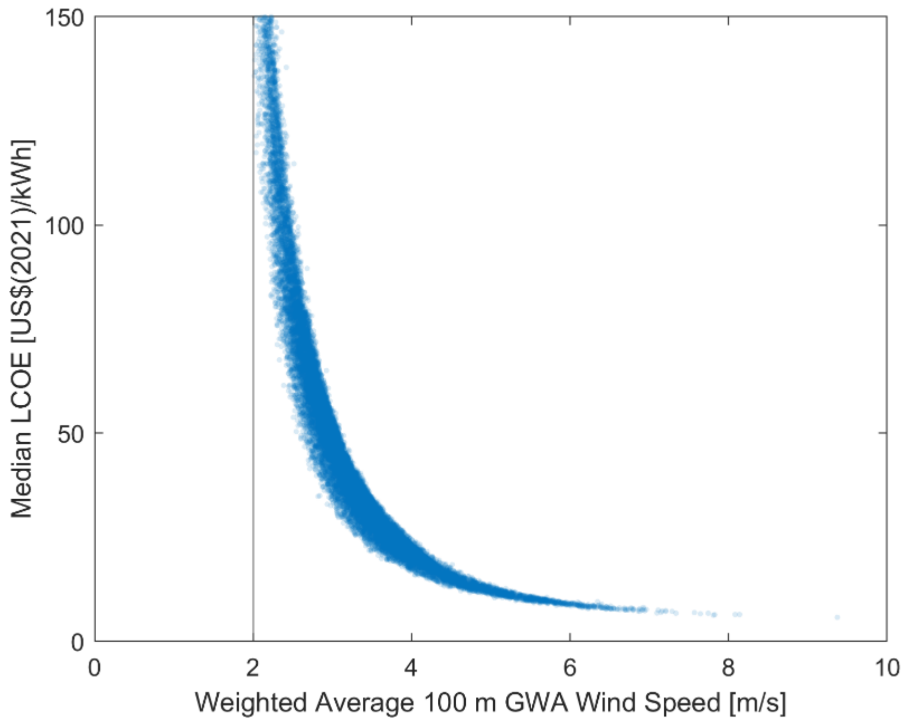


Figure 26. Median levelised cost of electricity vs. average 100 m GWA wind speed per meshed polygon. For clarity, the graph is limited to wind speeds ≥ 2 m/s and LCOE ≤ 150 US¢(2021)/kWh as the LCOE move towards infinity at smaller wind speeds.

Our LCOE range of 5.8–24.5 US¢(2021)/kWh is wider than the 14.6–14.9 US¢(2020)/kWh by [249] and 7.4–16.1 US¢(2019)/kWh by [66], which stems from differences in technical and economic assumptions, like CAPEX, as well as thresholds, e.g. for capacity factors and minimum wind speed. But since the ranges above are in the same order of magnitude, we see our results in line with existing work.

Figure 27 shows the median LCOE of onshore wind farms across Indonesia at sites with average 100 m wind speeds ≥ 4 m/s, as well as the ranges of local electricity tariffs. Most of the low-LCOE sites are situated in the high-capacity-factor areas in East Nusa Tenggara, Maluku, Java, South Sulawesi, and at the southern part of Papua. On Kalimantan and Bali, LCOEs are not as low, but still below 13 US¢(2021)/kWh. With LCOE below 9.5 US¢(2021)/kWh, onshore wind would be cost competitive against all other currently deployed power generation technologies in Indonesia, including subsidised fossil-fuelled plants [66].

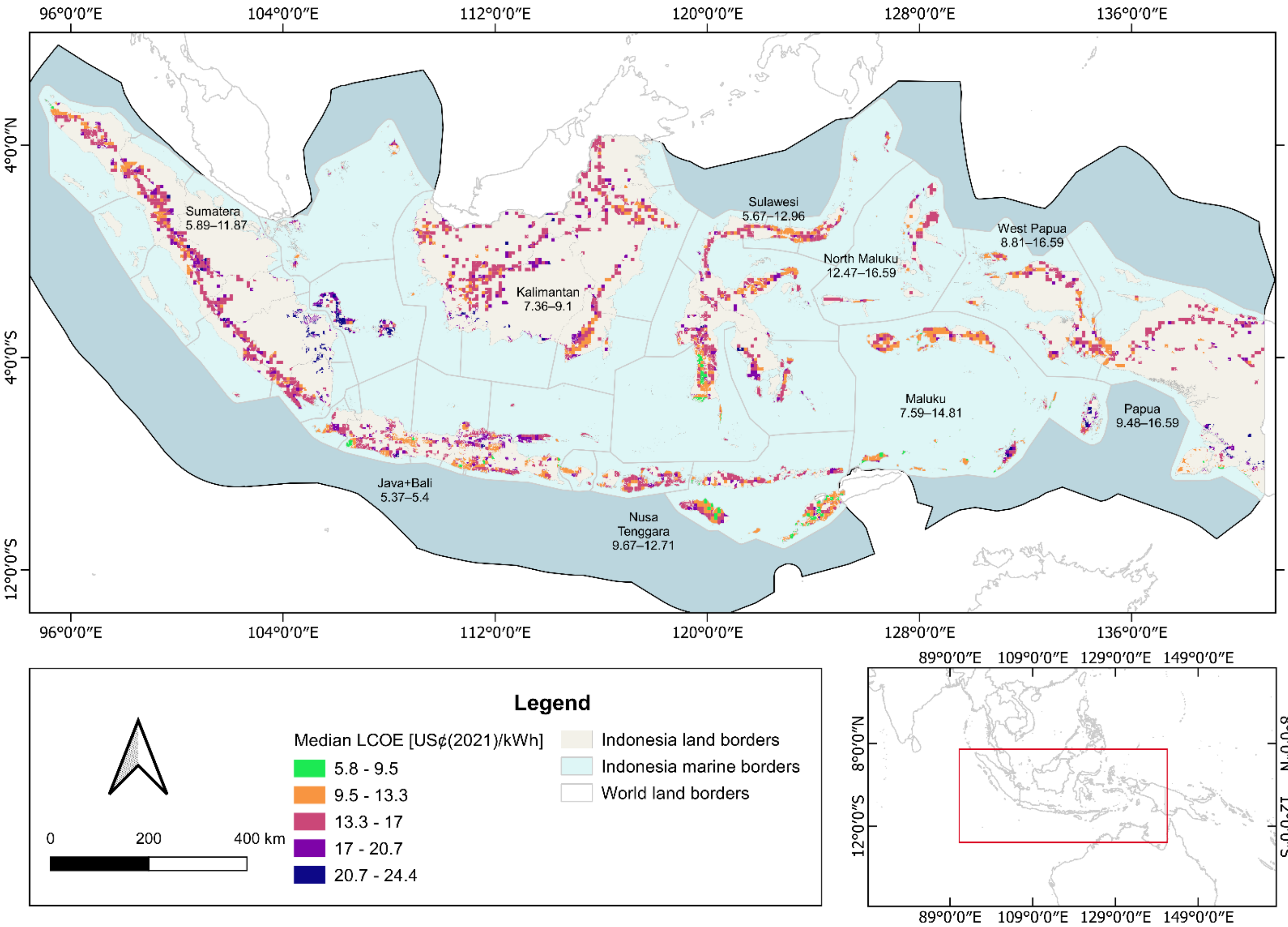


Figure 27. Median LCOEs of onshore wind farms in Indonesia with average 100 m GWA wind speeds ≥ 4 m/s. For each island (group), the range of minimum and maximum received electricity tariffs are shown. The tariffs are based on the BPP scheme and inflation corrected as described in section 2.3.3.

The cost supply curves of onshore wind in Indonesia are depicted in Figure 28. Using all flexible land, more than 50% of Indonesia's 2030 electricity generation could be provided at LCOEs of roughly 12.5 US¢(2021)/kWh. With more restrictions on land types, the supply curves become much shorter and steeper as gradually more sites with potentially high wind resources are filtered out. With open land, only 31 TWh/year could be produced at 12.5 US¢(2021)/kWh.

Note that the costs of distance-dependent cost components, like grid and road connection costs, are not adequately reflected so far. In Box I at the end of this sub section, we reflect on the impact of including grid and road connection costs.

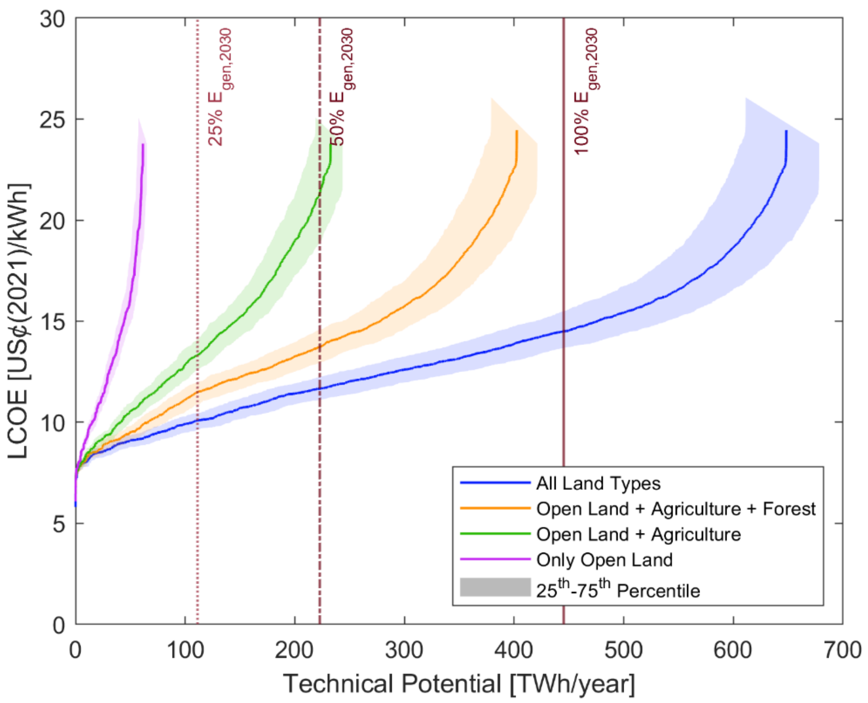


Figure 28. Cost supply curves of onshore wind power in Indonesia at sites with 100 m GWA wind speeds ≥ 4 m/s for different land use restrictions against various shares of the projected electricity generation $E_{gen,2030}$ in 2030. The LCOEs do not include the costs of local grid connection and extension.

Figure 29 shows the economic potential of onshore wind on all flexible land and only open land for different carbon taxes. Without considering a carbon tax and local electricity demand, the economic potential ranges between 20–126 TWh/year (only open land and all flexible land, respectively), and decreases to a demand-restricted range of 16 TWh/year, or 4% of national 2030 demand. This is because all of the economic potential is situated in East Indonesia (Nusa Tenggara, Maluku, and Papua), where resources are plentiful but electricity demand is low. A carbon tax of roughly 100 US$/t$CO_2$e could help spreading the economic potential to high-demand regions, like Java and Bali, with an electricity-demand-restricted range of 31–212 TWh/year, or 7–48% of 2030 demand. Such a carbon tax would be much higher than the current Indonesian carbon tax of 2.1 US$(2021)/t$CO_2$e [208], but lower than the ones in Sweden, Switzerland, and Liechtenstein [207]. Furthermore, such a tax rate would be similar to the price of EU Emission Allowances, which temporarily traded for 105 US$/t$CO_2$e (96 €/t$CO_2$e) in February 2022 [250]. However, such a high carbon tax might not be socially accepted as the increases in conventional power production costs could be passed down to consumers via increased electricity prices. Therefore, we recommend more research on how a socially acceptable carbon tax could be implemented without disadvantaging vulnerable groups in Indonesia.

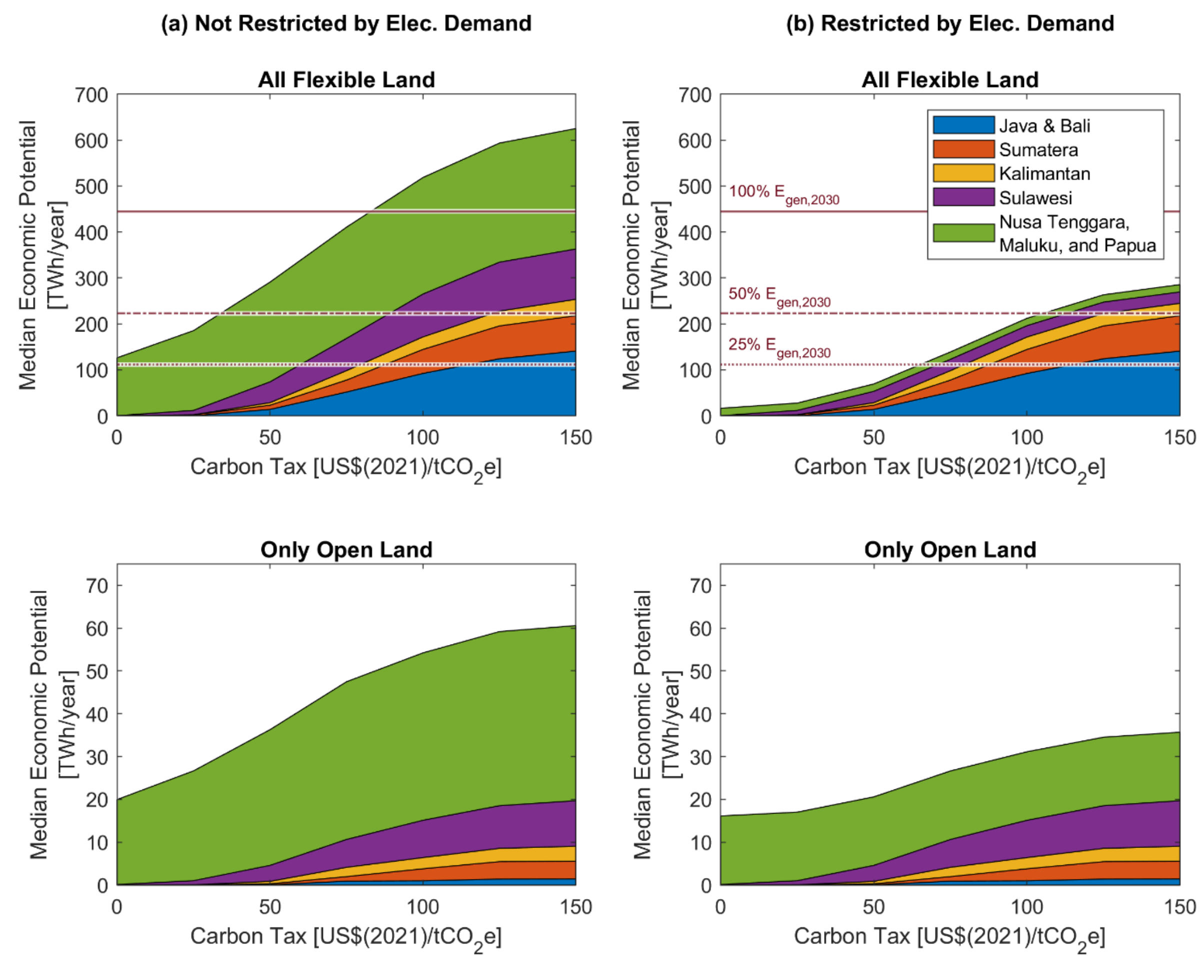


Figure 29. Median economic potential of onshore wind per island (group) for different carbon taxes. The wind farms are situated on open and all flexible land. The potentials in (a) comprise all wind farms with LCOE ≤ local electricity tariff plus carbon tax without considering regional electricity demand, while the potentials in (b) are capped at the projected local electricity generation in 2030. The economic potentials are shown for wind farms on any flexible land (top row) and only open land (bottom row). The legend as well as electricity demand lines apply to all subplots.

Box I

The costs of connected the wind farms to the existing grid and road infrastructure are not included in the paper underlying this chapter. In this box, we estimate the impact of these cost components on the LCOE and economic potential. Figure 30 displays the LCOEs with and without distance-dependent grid and road connection costs using the average component cost obtained during the solar PV study, see Table 19 in chapter 5 (grid connection costs: 2,308 US$(2021)/km$_{grid}$/kW, road construction costs: 286,992 US$(2021)/km$_{road}$).

The median increase of LCOE is 7.2%, while the maximum increase is 819% at a site 335 km and 120 km away from the closest substation and road, respectively. Aligned with Figure 25, sites in East Indonesia tend to be more affected by these costs due to the less extensive grid and road infrastructure there. If the LCOEs are compared to the local tariffs applicable during this study, the economic potential decreases from 126 TWh/year to 70 TWh/year (all types of land, not restricted by electricity demand).

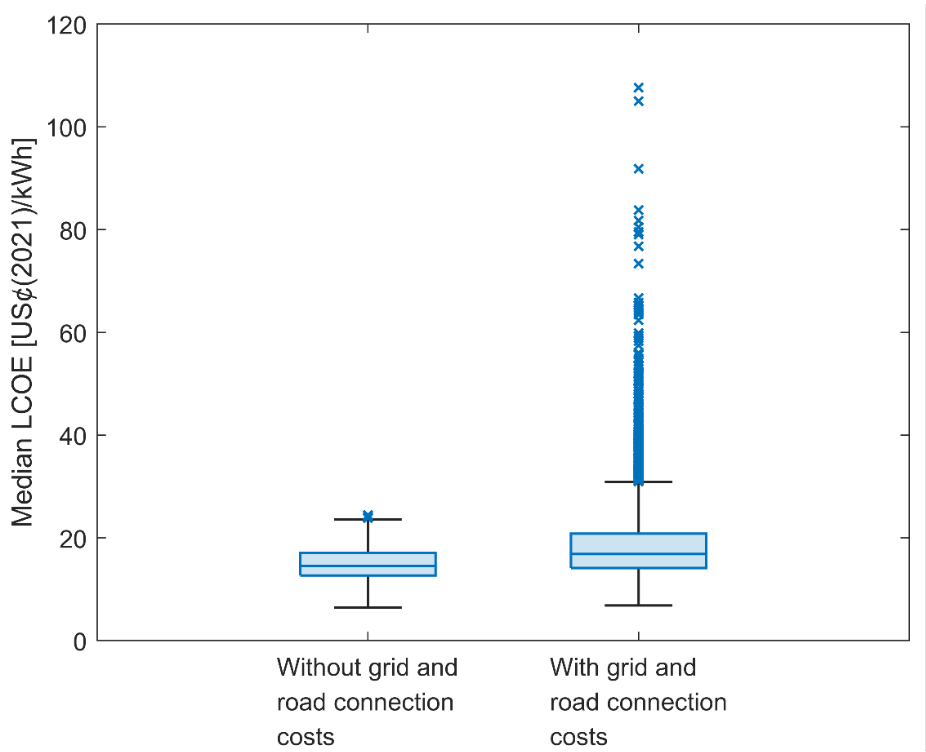


Figure 30. Comparison between LCOEs with and without grid and road connection costs. This illustration was made for the dissertation and cannot be found in the paper underlying this chapter.

3.4. Sensitivity analysis

Figure 31 visualises how our results are affected by (1) uncertainties in input data (wind speed, CAPEX, OPEX, discount rate, BPP), (2) development of input data (CAPEX, OPEX, discount rate, BPP), and (3) design choices (hub height). Our results are the most sensitive to the wind speed. Therefore, we recommend to validate our results with measured long-term data, which was not possible for this research. There have been previous measurement campaigns in Indonesia, but, to our knowledge, only at heights between 30–50 m [65]. Future campaigns could take place at heights between 80–130 m at technically and economically attractive locations as suggested in this chapter. The CAPEX and discount rate also considerably affect the economic outputs of this research. This indicates that onshore wind's economic potential in Indonesia might not be as high as projected here while experience with the technology is still limited. Then again, the industry expects the technology's costs to decrease further in the future [199]. Once onshore wind gains traction in Indonesia, costs might decline below the costs assumed here and higher economic potentials might be possible. Out of all outputs, the economic potential is by far the most sensitive, which is in agreement with previous research [189]. Therefore, we suggest to re-assess Indonesia's economic onshore wind potential once the technology progressed further, a better understanding of investment and financing costs has been gained, or if new tariff and support schemes are introduced.

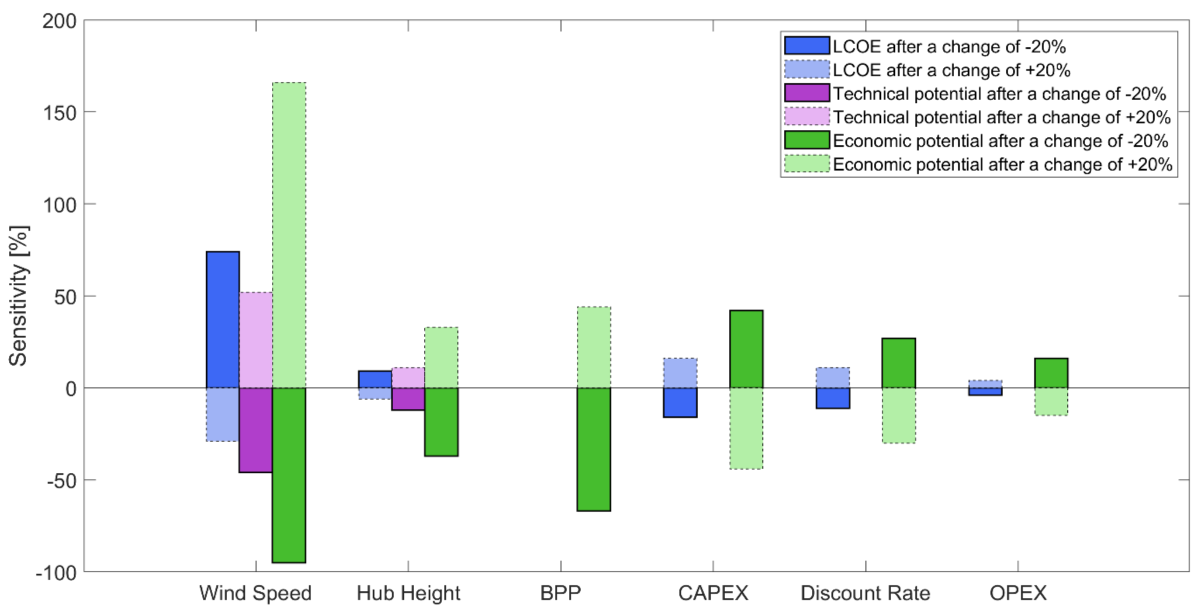


Figure 31. Sensitivity of median LCOE, technical potential, and economic potential to changes in model parameters by ±20%. LCOEs and potentials are calculated per meshed polygon with weighted average 100 m GWA wind speed of ≥ 4 m/s (sample size: 5,242 polygons). The economic potential refers to original electricity tariffs without carbon tax.

4. Conclusions

This chapter proposes a method to account for the variability of site selection criteria when mapping onshore wind potentials. Our motivation stems from the shortcomings in current literature, where site exclusion criteria are often used in a binary, in-or-out fashion. We distinguish between static site selection criteria, which always apply, and flexible criteria, which may require further scrutiny due to site-specific properties like wind speed and elevation and the impact on stakeholders from agriculture and forestry, amongst others. To assess the technical and economic performance of onshore wind, we use 20 years of bias-corrected ERA5 wind speed data, 28 power curves, and a turbine-specific cost model. We demonstrate our method for Indonesia, a country with rising electricity demand and high fossil fuel dependency.

We find that flexible exclusion criteria can increase the transparency and usefulness of resource mapping analyses. The impact of individual criteria can be measured and thresholds for site exclusion fine-tuned accordingly, for example the economic minimum average wind speed at hub height of 4 m/s. Furthermore, our approach shows how much land per land type would be required to cover certain shares of present and future demand, which enables more informed recommendations for policymakers and capacity planners. Flexible criteria from built-up infrastructure reveal the individual, regional challenges of the energy transition in urbanised and rural areas. Minimum distance to road and settlements are significantly more impactful in urbanised regions, like Java and Bali, while maximum distance to next substation is most effective in rural areas with less-developed grid infrastructure. With these insights, more direct policies can be developed addressing stakeholders affected by wind farm deployment and their (potentially conflicting) interests. Of course, policy recommendations could already be deduced from the previous, binary resource mapping method, but we believe that our flexibility-based method can add considerable depth to them.

For our case study Indonesia, we report a technical potential of 207–1,994 TWh/year. The high end of the range could cover more than 50% of 2030 electricity demand on all islands. LCOEs range between 5.8–24.5 US¢(2021)/kWh with an electricity-demand-restricted economic potential of 16 TWh/year, which improves to 31–212 TWh/year with a carbon tax of 100 US$(2021)/t$CO_2$e. We conclude that onshore wind may not be suitable for Indonesia's national energy transition. However, with sufficient policy support, it could become an important complimentary technology in regions with sufficient wind resources.

The methods presented here could be improved further by addressing the limitations of our study, namely (1) limited site adaptation of wind farm design and assessment via constant turbine spacing, wake efficiencies, and availability factors, (2) omission of system integration cost and land-type-specific cost, and (3) omission of economies of scale and technological learning.

5. The technical, socio-economic, and bankable potential of ground-mounted, utility-scale solar PV

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 chapter 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, 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/year 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/year 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.

Chapter 5: The technical, socio-economic, and bankable potential of ground-mounted, utility-scale solar PV

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Abbreviations, Symbols, and Indices

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	%

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 [11,12,64]. 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 chapter, 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 [35] has been implemented, generating 4.5% of global 2022 electricity production [251]. Hence, we might still only be at the inception of PV's global spreading despite its rapid growth in the last decades [252]. 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 17 lists current studies that use geospatial analysis to investigate PV's economic potential.[3] The standard approach in literature is to first map the technical potential across the studied region, either with [32,206,253–256] or without [257,258] 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 [257], and the use of future instead of present costs [206].

Although current studies provide useful insights into PV's technical potential and LCOEs, we detect five limitations. First, only one study [255] 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 [206,255,257] 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 [206] 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 [255,258] 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

[3] See Appendix F for the search queries and sampling methodology. For explanations of the economic and financial terms used in this chapter, see the glossary in Appendix G.

analyses merely provide snapshots under current conditions as only one study explored policy-support options, like feed-in tariffs [255], to enhance the economic potential.

Table 17. 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 Appendix B 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?
[253]	India	LCOE	10%	51.6–89 US$/MWh	5.2–9.0	–	–
[254]	Morocco	LCOE	5%	0.0331–0.0618 US$/kWh	3.3–6.2	LCOE = 0.0365 US$/kWh	–
[206]	Mexico	LCOE	8%	23–35 EUR/MWh	2.8–4.2	LCOE ≤ 0.07 EUR/kWh	–
[255]	Fujian, China	LCOE, NPV, PBP	8%	0.16–0.27 US$/kWh	18.2–30.8	NPV > 0 US$	Sensitivity analysis (performance ratio, rooftop-to-built-up-area ratio, popularizing ratio)
[32]	West Kalimantan, Indonesia	LCOE	–	4.47–5.46 US¢/kWh	4.5–5.5	Average cost of other generation technologies	–
[256]	China	LCOE	9%	0.12–6.2 US$/MJ	43.2–2,230	–	–
[257]	Jordan	LCOE, NPV, PBP	5%	0.025–0.0477 US$/kWh	2.5–4.8	LCOE ≤ 0.05 US$/kWh	–
[258]	Chile	LCOE, NPV, IRR	5%	–	–	IRR ≥ Required rate of return	Sensitivity analysis (CAPEX, discount rate)

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 [259]. Here, we provide a brief overview [234,259–262] 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% [261]. 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 [262–264], with which calculations are performed repeatedly with randomised inputs. From the resulting distribution of outputs, the exceedance probability can be derived via pX values [234,262,264]. A p90 value, for example, is the value that is exceeded by 90% of the total sample. In solar energy literature, the irradiation and plant's productivity have been randomised [262,265,266], 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 [261]. 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.

1.4. Scope, objectives, and outline of this chapter

This chapter 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 [14], but slow in implementation [54] due to suboptimal financing conditions, amongst others [56]. 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-enhanced conditions.

We aim 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 chapter 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, and 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 Figure 32.

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 18 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. [267], across PV's useful lifetime goes beyond this study's scope. Nonetheless, land use change's impact on available land for PV should be addressed in future research.

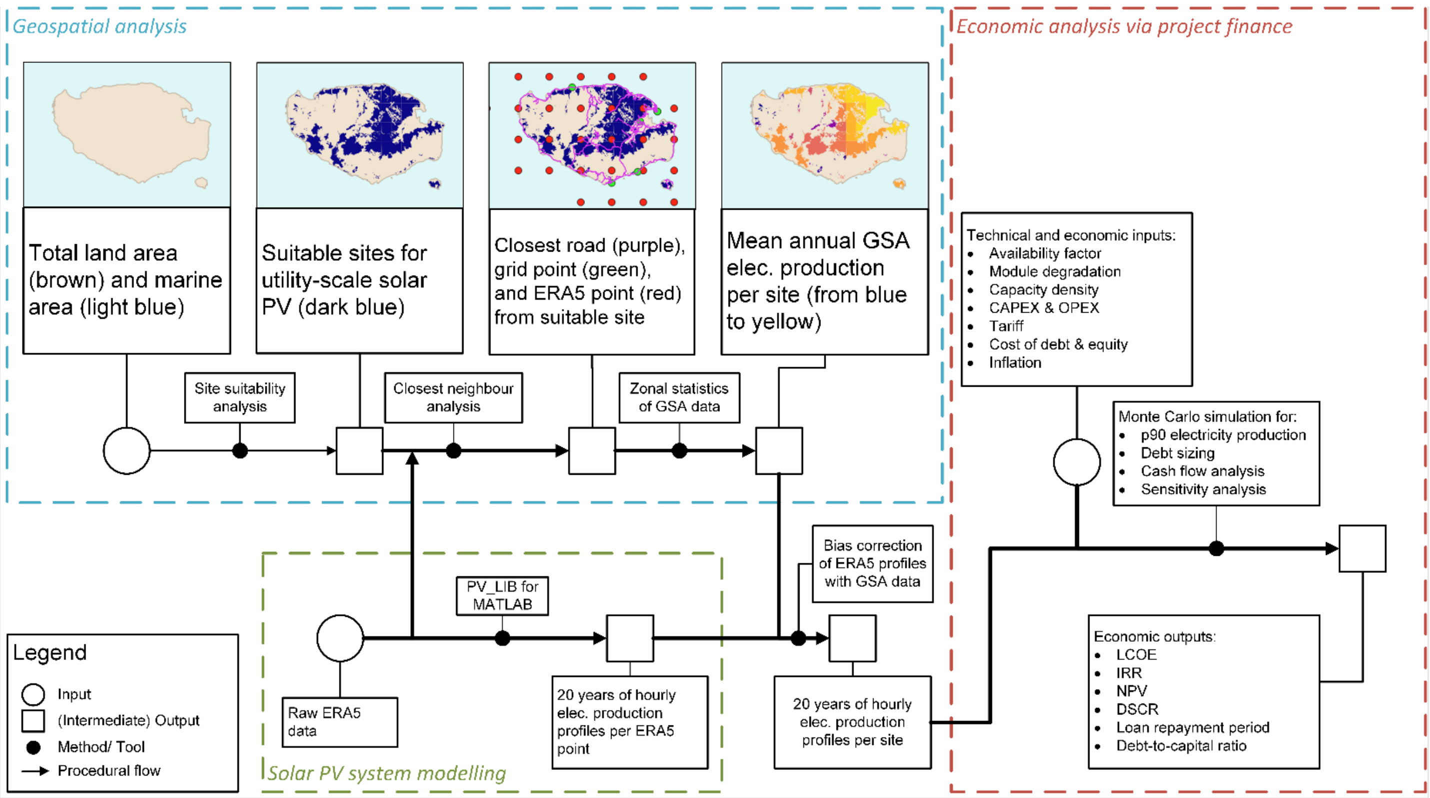


Figure 32. Overview of the framework presented in this study.

After obtaining the technically feasible PV sites, we add the sites-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 [227] and grid connection point [226,268]. 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 [14], affecting 0.04% of all sites, to ensure a minimum PV plant size of 1 MW_p.

Table 18. Site selection criteria used in this research. Unless stated otherwise, the land use data originates from [222].

Exclusion group	Exclusion layers [Ref]	Layer type + Resolution	Threshold/ Buffer
Geography	Slope [166]	Raster, 463 m	Slope ≥ 15°
	Volcano [223]	Vector	2,000 m
Water bodies/ wetlands (buffers from [253,269])	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 [270]	Vector	300 m
Built-up infrastructure (buffers from [206])	Settlements	Vector	200 m
	Transmigration area	Vector	200 m
	Airports/ harbours [224]	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 [206])	Nature conservation zones [225]	Vector	1,000 m

2.2. Solar PV system modelling and technical potential

We use the *PV_LIB Toolbox for MatLab* [271] to model the PV systems with the technical assumptions listed in Table 19. All used datasets and PV_LIB functions are listed in Appendix H.

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 [272], and calculate the tilt angle based on the sites' latitude [273]. Then, we use this incident irradiance to calculate the operating cell temperature, and further correct it for 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% [272].

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* [34], 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-hour time step of the ERA5 power profiles. For example, if the average GSA value at a site is 5% higher than the corresponding average ERA5 value, each 1-hour 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.

Table 19. 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 [271] and manufacturer datasheet [274]
Peak power module [W_p]	400	
Module area [m^2]	1.99	
Material	mono-Si	
Module tilt [°]	*latitude* × 0.87	[273]
Albedo coefficient	0.25	[275]
DC-side efficiency [%]	94.6	[272]
AC-side efficiency [%]	96.0	[272]
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	[14,276]
Module degradation [%/year]	0.5–1	[234]
Economic solar PV parameters		
Specific CAPEX for grid connection [US$(2021)/MW/km]	847–3,769	[277]
Specific CAPEX for road construction [10^3 US$(2021)/km]	134.7–439.3	[32,278,279]
Specific system CAPEX excl. grid and road [US$(2021)/$kW_p$]	680–1,583	[32,66,178,252,276,280] + [personal communication, SOE#1, SOE#2, Private sector #2, and Private sector #3]
OPEX [US$(2021)/$kW_p$/year]	8–32	
Financial parameters for debt sizing and cash flow analysis		
Depreciation period [years]	16	[281]
Depreciation rate (straight-line) [%/year]	6.25	[281]
Salvage value [US$]	0	
Corporate tax rate [%]	20	[281]
Tariff [US¢(2021)/kWh]	5.02–16.59	See Appendix I.
Inflation [%]	1.5–5	Period 2017–2022 [282]
Initial debt-to-capital ratio	60–80%	[66,178,252,283] + [personal communication, SOE#1, SOE#2, Private sector #2, and Private sector #3]
Initial DSCR for debt sizing	1.3	[264]
Initial loan repayment period for debt sizing [years]	20	
After-tax cost of debt [%]	5.0–10.0	[178] + [personal communication, SOE#1, SOE#2, Private sector #2, and Private sector #3]
Cost of equity [%]	12.0–13.8	[178,283], excluding size premia

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 [12,284], 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$/year (inflation-adjusted average values from [66]), real *Weighted Average Cost of Capital (WACC)* = 9.5% [66] + (personal communication, SOE #1 and SOE #2, private sector #2 and private sector #3), and lifetime *T* = 20 years. For the annual electricity production *AEP*, we multiply the sites' areas with their respective GSA values and average capacity density of 60 MW$_p$/km^2 from Table 19.

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 [73]. 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 Appendix I) for the bankable potential. During the finalisation of the study, a new tariff scheme was announced [285], to which we refer where relevant.

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

2.3.2. Bankable potential

For the bankable potential, we use the financial model in Figure 33, 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 19 originate from academic and grey literature as well as expert elucidation. We contacted the eight experts listed in Appendix J to source and validate the used input data and metrics. All monetary inputs are converted to US$(2021) using Appendix B. 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 Appendix K.1 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.

The cash flow analysis module calculates the metrics in Figure 33 to determine PV's bankable potential (see Appendix K.2 for equations). These metrics comprise the LCOE [286], NPV [262], IRR [12], loan repayment period, and operational p90 DSCR. In line with practice [234], 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 ≥ 0 US$/kW$_p$ [260]
- Operational p90 DSCR ≥ 1.3 [261]
- IRR ≥ minimum IRR + risk premium 0–10% [261]
- Loan repayment period ≤ 8–18 years [261]

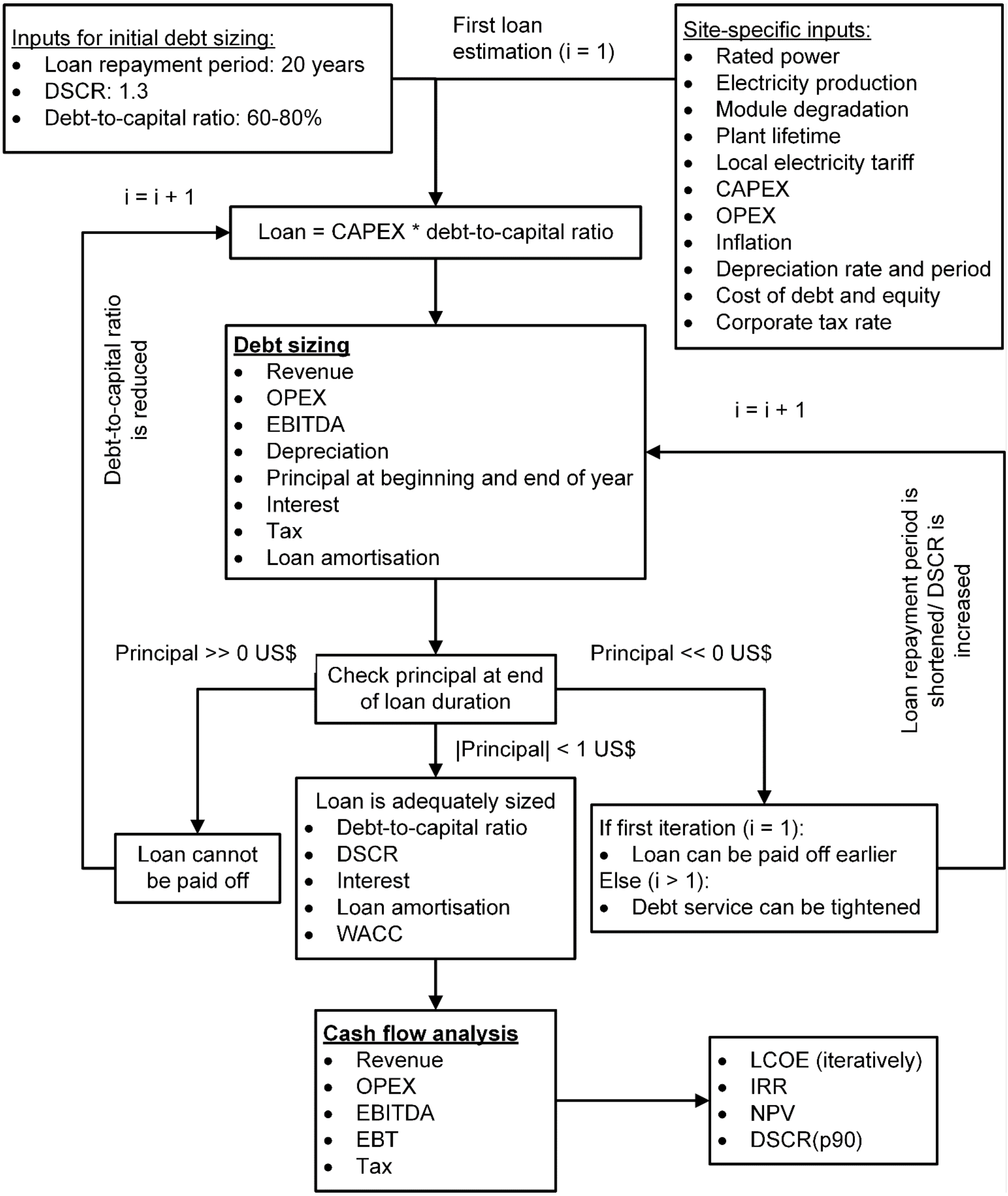


Figure 33. Overview of the financial model, see Appendices K.1 and K.2 for equations.

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 [261]. 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 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.

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 19. 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 19 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 20 shows how much land and PV capacity are removed per site exclusion group. Under current land use, 92.1% of Indonesia's land is 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 Figure 34, the p90 capacity factor ranges between 8.9–18.5%. Moreover, our PV system model tends to overestimate power production with bias correction factors between 0.83–1.02 on the 90% confidence interval (see Figure 35). 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 [14] and 1.3 TW_p [35], 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 [9] 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 3.3).

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.

Table 20. 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**

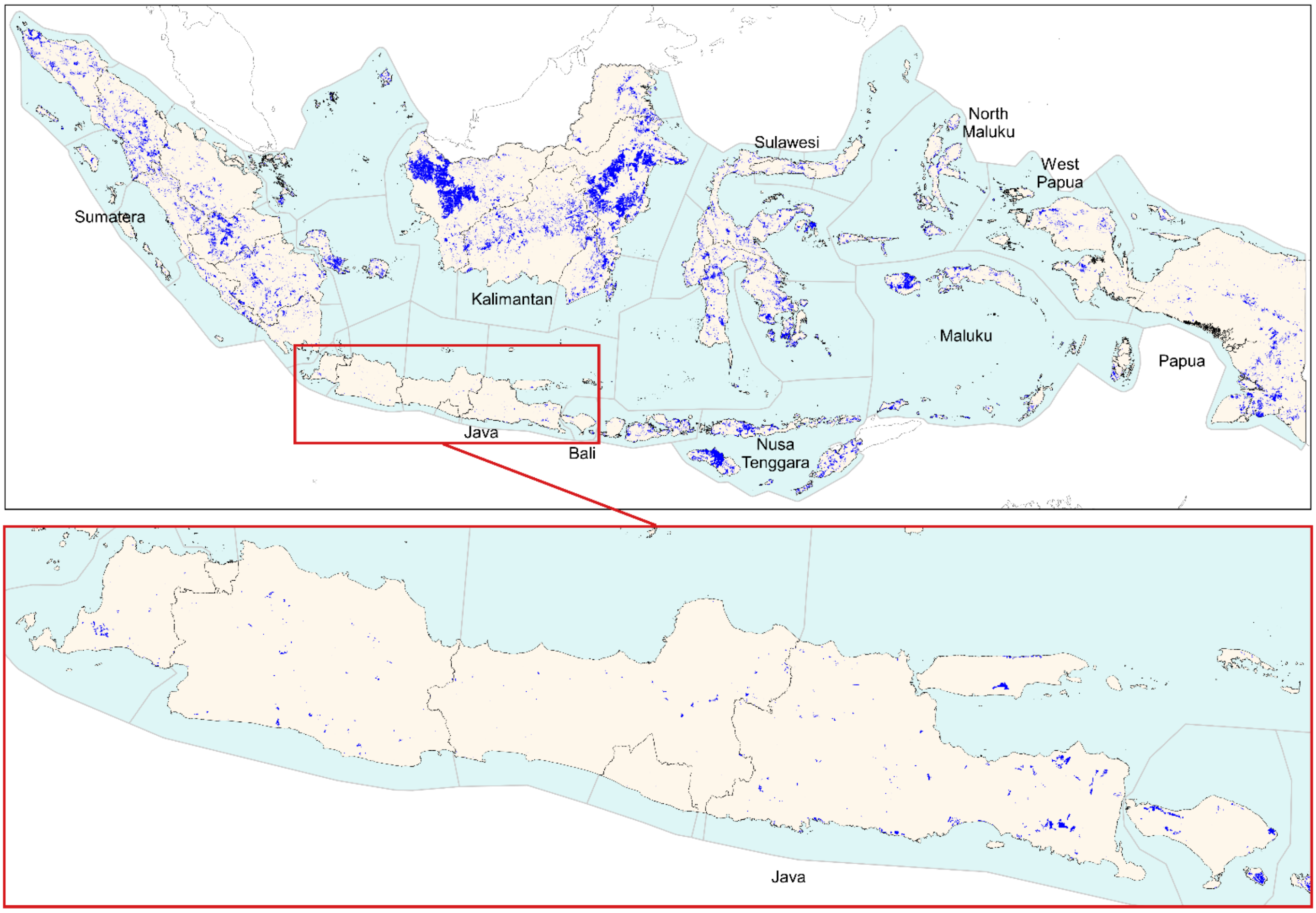


Figure 34. Suitable sites for utility-scale PV (dark blue) on Indonesia's land area. The bottom image zooms in on Java and Bali. The white areas are neighbouring countries; the light blue areas are marine provincial borders.

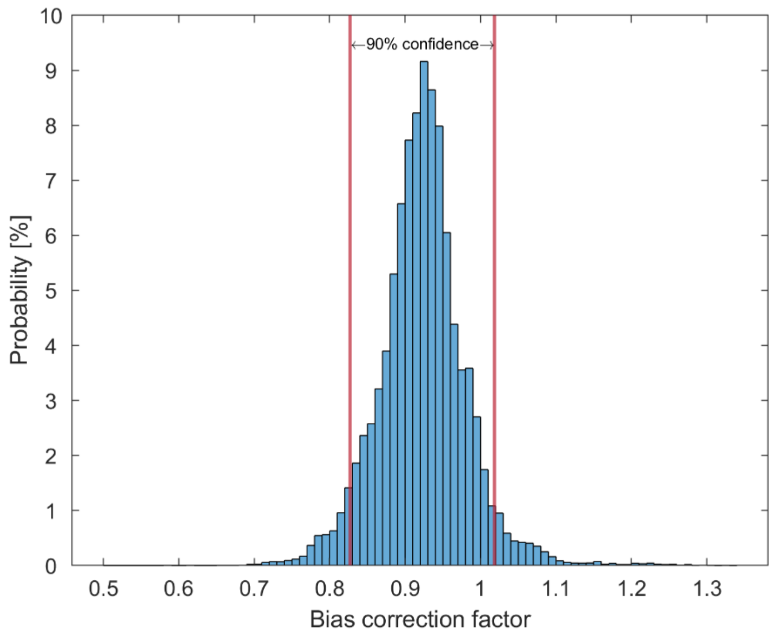


Figure 35 Distribution of bias correction factors across PV sites in Indonesia and their 90% confidence range.

3.2. Socio-economic and bankable potential

3.2.1. Socio-economic potential

Figure 36 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 [66] 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 21, 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.

3.2.2. Bankable potential

Figure 37 and Figure 38 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 [198]. 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 [283]. The loan repayment periods of these projects was 15–16 years [283], 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 [287]. 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 [283].

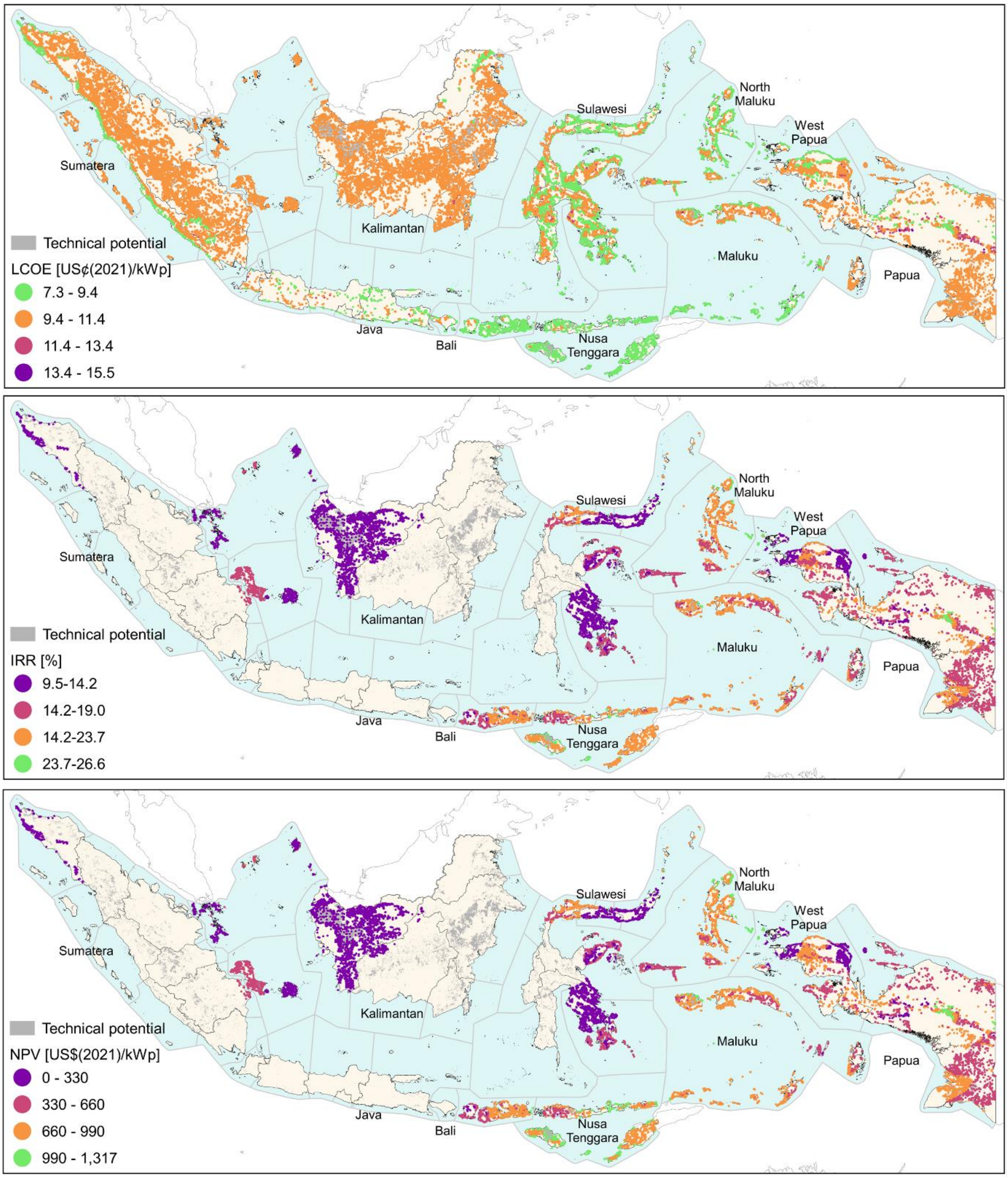


Figure 36. LCOE, IRR, and NPV of utility-scale PV in Indonesia forming the socio-economic potential. For better visibility, only sites with NPV ≥ 0 US$/kW$_p$ and IRR ≥ WACC 9.5% are shown as magnified points.

Table 21. Technical and socio-economic potential per island group.

Island (group)	Technical potential [TWh/year]	2030 demand [9] [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**

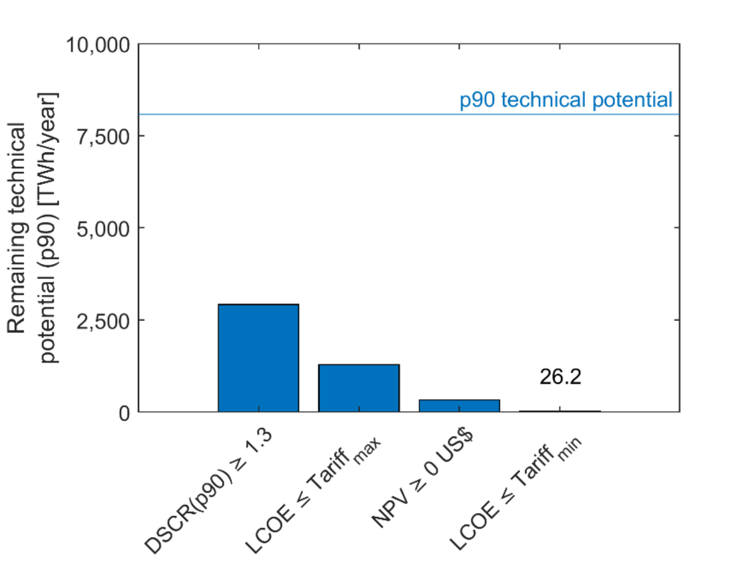


Figure 37. Impact of DSCR, tariff, and NPV thresholds as criteria for PV's p90 bankable potential.

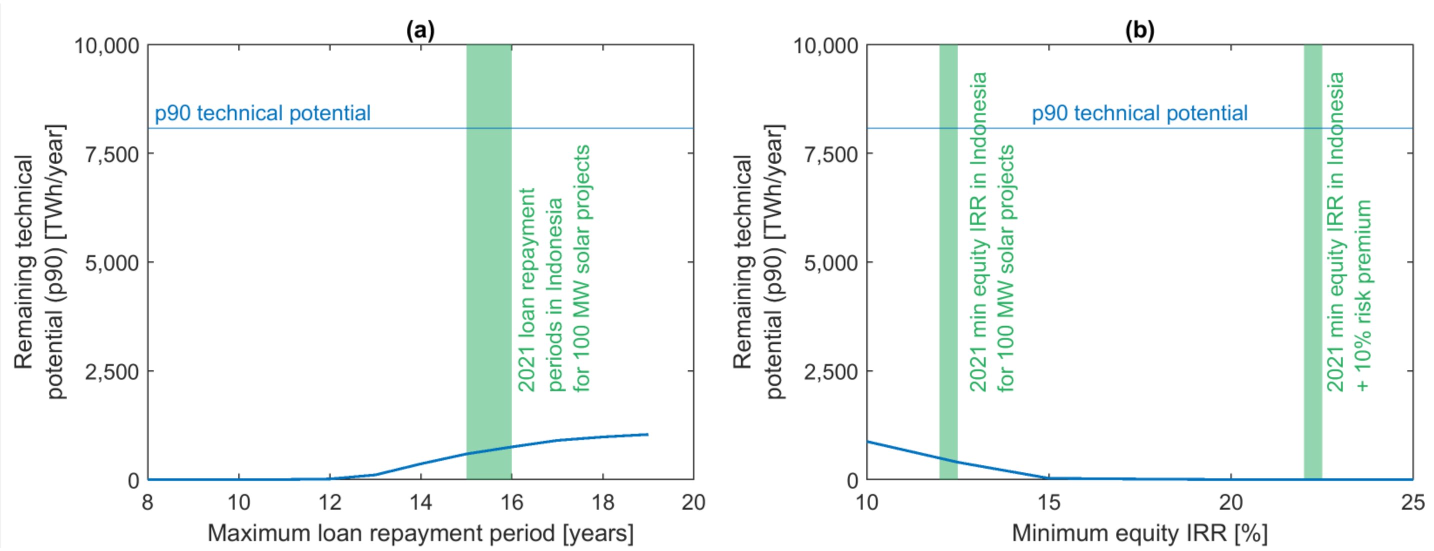


Figure 38. Impact of maximum loan repayment period and minimum equity IRR on PV's p90 bankable potential. The green patches show thresholds found in practice for Indonesia [283] *as well as general practice from literature* [261].

Figure 39 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 North Maluku, 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 [5]. Today, more than half of Indonesia's solar capacity is installed in East Indonesia [288], e.g. as solar lamps [65] and Diesel generator replacements [289]. 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 [9] 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 [289]) 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 19, 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 potentials, e.g. from economies of scale mostly omitted in this study, could explain why recent bid prices were so low.

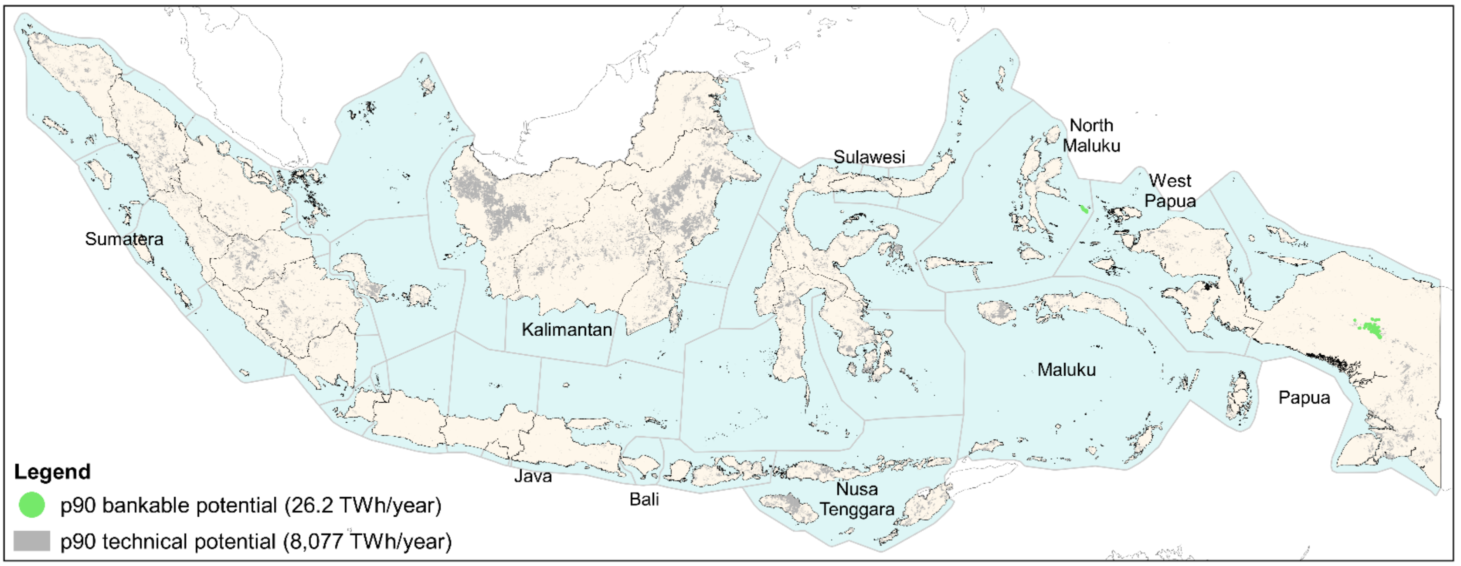


Figure 39. Map of bankable p90 bankable potential across Indonesia using LCOE ≤ minimum tariff, IRR ≥ 12.5% and loan repayment period ≤ 15 years as thresholds. The sites with bankable potential are displayed as magnified green points for clarity. The p90 bankable potential in this illustration does not account for 2030 electricity demand.

Table 22 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.

Table 22. 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 138.9°E, 4.0°S	East Java 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

3.3. Sensitivity analysis and impact of policies

Figure 40 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%).

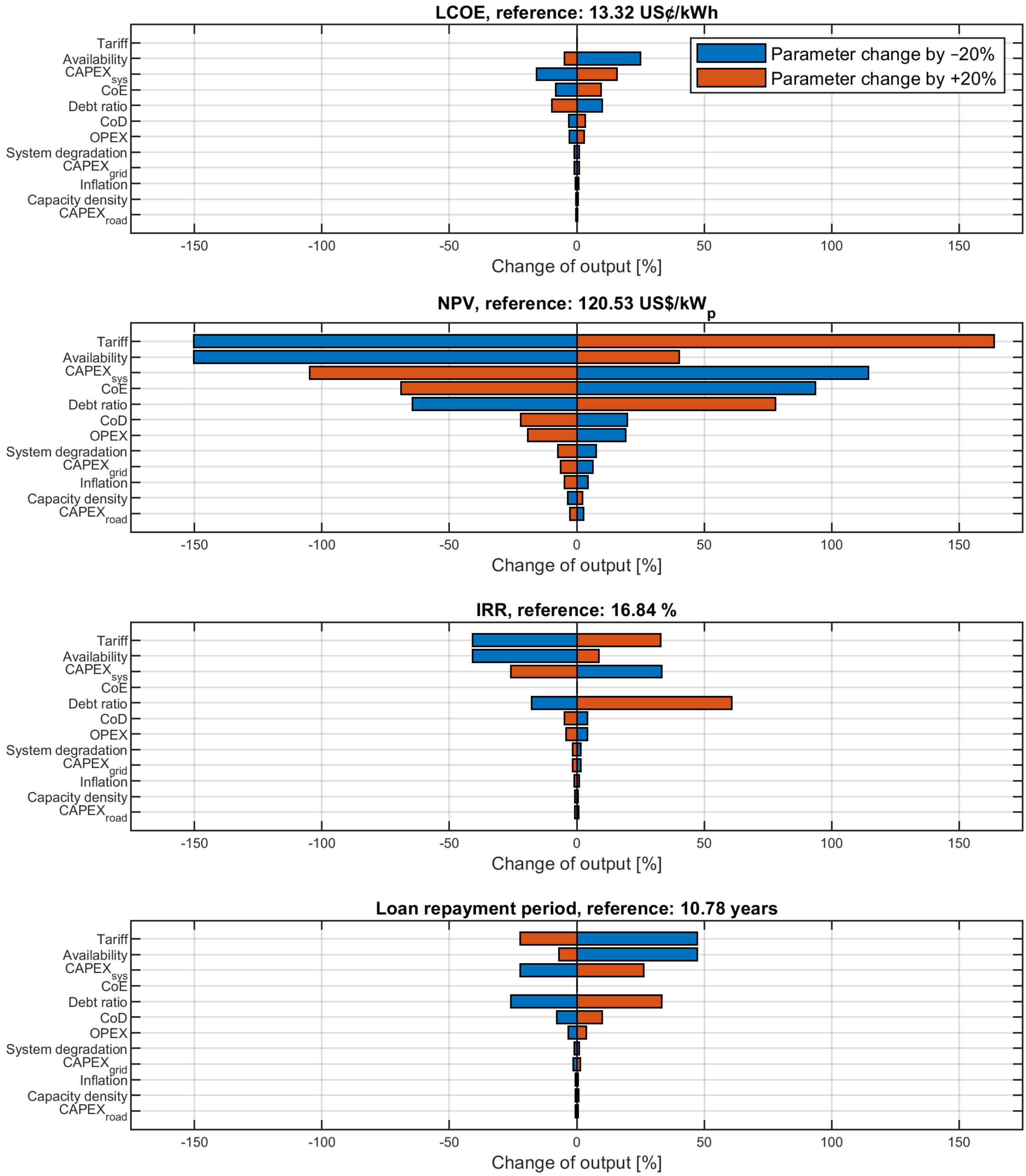


Figure 40. Sensitivity analysis for utility-scale PV sites with positive median NPV (6,390 out of 38,143 sites). All inputs are varied by +/– 20% except for the availability factor, which cannot exceed 100%.

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 [290] 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-owned utility company PLN.

Figure 41 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 [252]. 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$/t$CO_2$eq would increase tariffs by 5.1 US¢(2021)/kWh [45] and moves the East Java plant closer to bankability. This tax rate is higher than Indonesia's current tax of 2.1 US$(2021)/t$CO_2$e [208], but comparable to 2020 carbon tax rates and emission allowances in Europe [207]. The East Java plant would receive between 10.50–11.35 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 [285]. 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 [238]. 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.

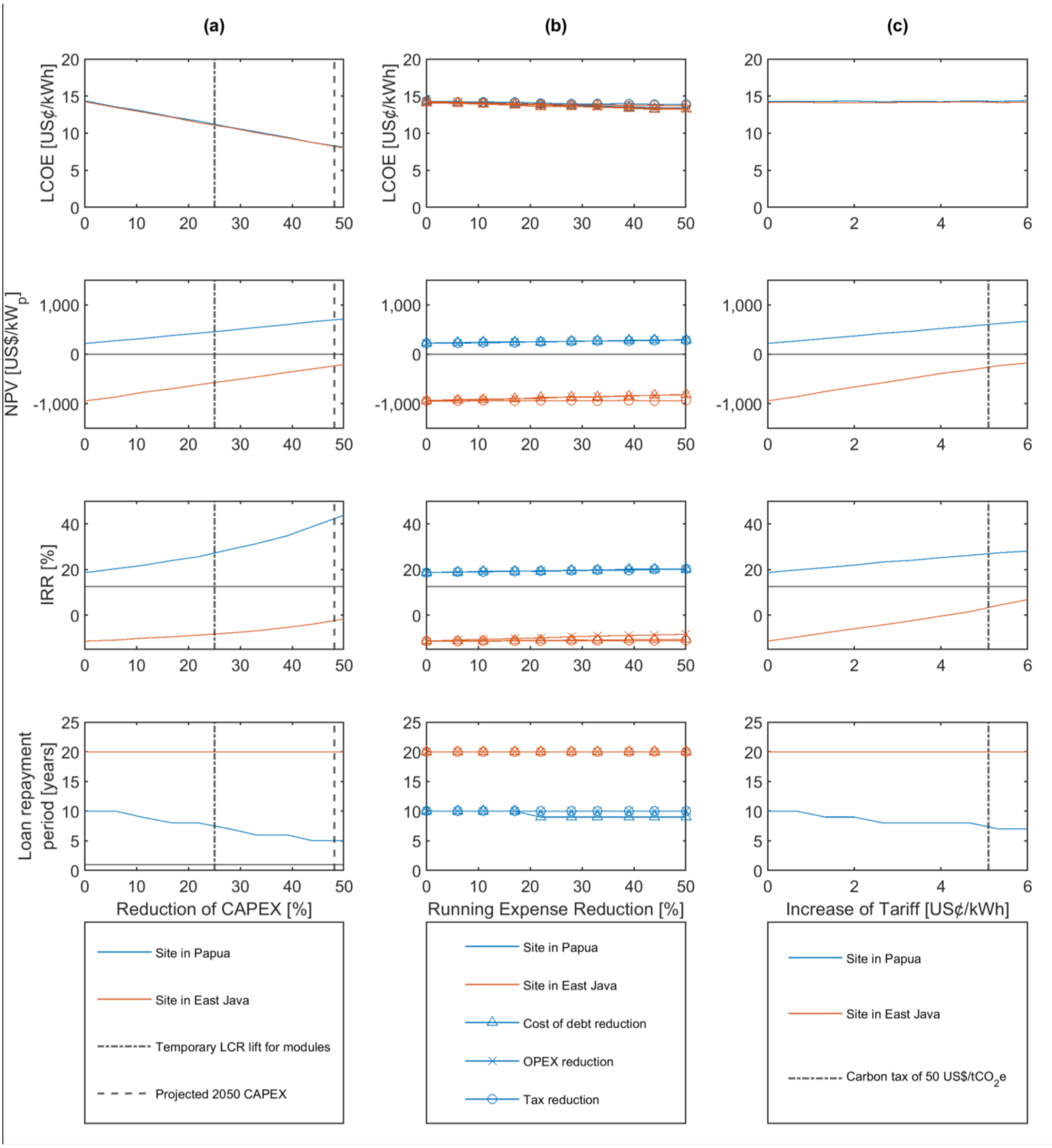


Figure 41. Impact of (a) CAPEX reduction, (b) reduction of running expenses, and (c) increase of revenue on p90 metrics pertaining to the two reference sites analysed in section 3.2.2. LCR: for local content rule. Projected 2050 CAPEX in Indonesia are taken from the technology catalogue by the National Energy Council [280].

Figure 42 and Table 23 present 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 [280]. As supported by Figure 41, the bankable potential might increase significantly if these projections hold true.

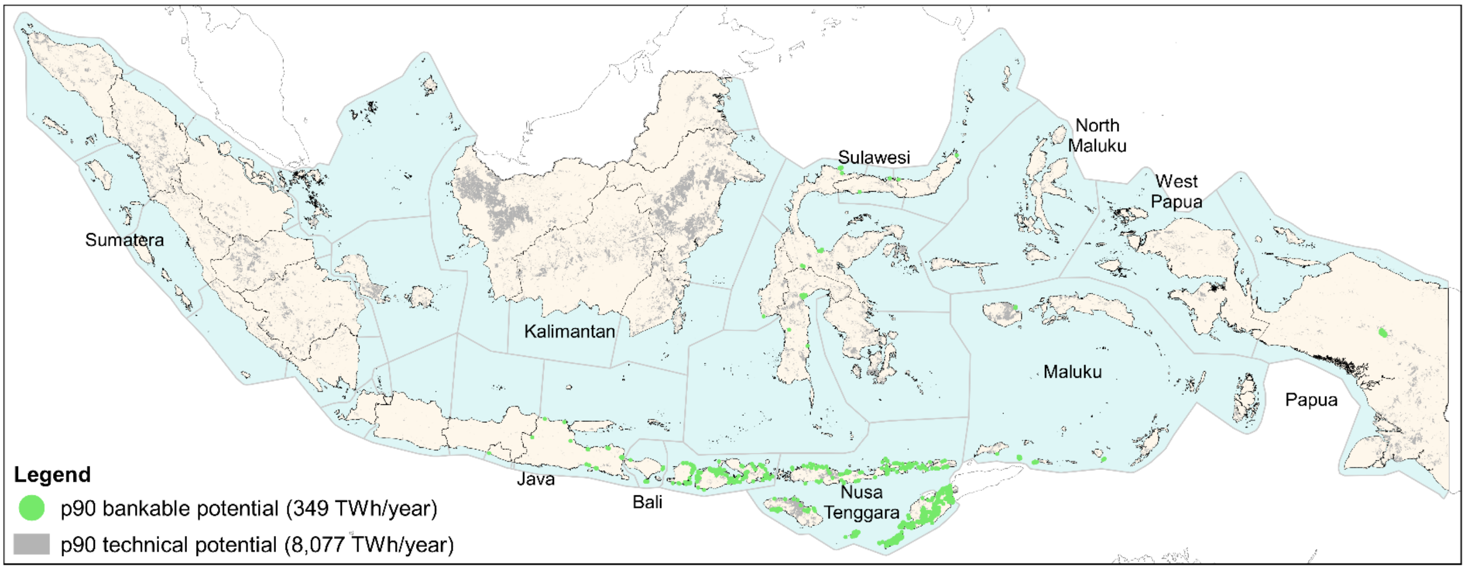


Figure 42. Map of bankable p90 bankable potential across Indonesia with a national feed-in tariff of 11.5 US¢(2021)/kWh and temporary lift of local content for solar modules. Thresholds for bankability are LCOE ≤ feed-in tariff, IRR ≥ 12.5% and loan repayment period ≤ 15 years. The sites with bankable potential are displayed as magnified green points for clarity. The p90 bankable potential in this illustration does not account for 2030 electricity demand.

Table 23. 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.

			Current conditions			FIT + Temporary LCR lift		
			p90 bankable potential [TWh/year]			p90 bankable potential [TWh/year]		
Island (group)	**p90 technical potential [TWh/year]**	**2030 demand** [9] **[TWh]**	**Not capped by demand**	**Capped by demand**	**Share of 2030 demand [%]**	**Not capped by demand**	**Capped by demand**	**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**

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 [235]. 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 [291] and would be more extensive on Papua than on Java and Bali given the limited transmission grid infrastructure of the former [9]. 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 [21]. Moreover, weather forecasting systems could help predicting PV's production and taking adequate balancing measures [292].

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 chapter 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 study 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.

6. The global technical and economic potential of Ocean Thermal Energy Conversion

Abstract: *Ocean Thermal Energy Conversion (OTEC)* is an emerging renewable energy technology using the ocean's heat to produce electricity. Given its early development stage, OTEC's economics are still uncertain and there is no global assessment of its economic potential, yet. Here, we present the model pyOTEC that designs OTEC plants for best economic performance considering the spatiotemporally specific availability and seasonality of ocean thermal energy resources. We apply pyOTEC to more than 100 regions with technically feasible sites to obtain an order-of-magnitude estimation of OTEC's global technical and economic potential. We find that OTEC's global technical potential of 107 PWh/year could cover 11 PWh of 2019 electricity demand. At ≥ 120 MW_{gross}, there are OTEC plants with *Levelised Cost of Electricity (LCOE)* below 15 US¢(2021)/kWh in 15 regions, including China, Brazil, and Indonesia. In the short to medium term, however, small island developing states are OTEC's most relevant niche. Systems below 10 MW_{gross} could fully and cost-effectively substitute Diesel generators on islands where that is more challenging with other renewables. With the global analysis, we also corroborate that most OTEC plants return the best economic performance if designed for worst-case surface and deep-sea water temperatures, which we further back up with a sensitivity analysis. We lay out pyOTEC's limitations and fields for development to expand and refine our findings. The model as well as key data per region are publically accessible online.

Chapter 6: The global technical and economic potential of Ocean Thermal Energy Conversion

This chapter was originally published as Langer J, Blok K. The global techno-economic potential of floating , closed-cycle ocean thermal energy conversion. J Ocean Eng Mar Energy 2023. https://doi.org/https://doi.org/10.1007/s40722-023-00301-1.

This chapter is the culmination of several OTEC-related articles created within and outside of the PhD project. Since it was not possible to showcase all of the articles in this dissertation, we added several boxes throughout the chapter that summarise their main findings.

Symbols and Indices

Symbol	Meaning	Unit ([-] if unitless)
$\dot{Q}$	Heat flow	kW
$\dot{W}$	Work	kW
$\dot{m}$	Mass flow	kg/s
ΔT	Temperature difference	K
Δp	Pressure drop	Pa
A	Area	m^2
a	Availability	%
b	Scaling coefficient	-
c	Specific heat capacity	kJ/kgK
capex	Specific capital expenses	US$(2021)/unit
CAPEX	Capital expenses	US$(2021)
CRF	Capital recovery factor	-
d	Inner pipe diameter	m
f	Friction factor	-
K	Pressure drop coefficient	-
l	Pipe length	m
LCOE	Levelised cost of electricity	US¢(2021)/kWh
n	Plant lifetime	years
NTU	Number of transfer unit	-
OPEX	Operational expenses	US$(2021)/year
r	Discount rate	%
T	Temperature	K, °C
U	Overall heat transfer coefficient	kW/m^2K
v	Velocity	m/s
ε	Effectiveness	%
η	Efficiency	%
ρ	Density	kg/m^3

Index	Meaning	Index	Meaning
0	Reference	*log*	Logarithmic
cond	Condensation	*mech*	Mechanical
CW	Cold deep-sea water	*net*	Net
D	Darcy	*out*	Outlet
el	Electric	*p*	Pressure
evap	Evaporation	*pipe*	Pipe
f	Factor	*pump*	Pump
gross	Gross	*t*	Technical
HX	Heat exchanger	*trans*	Power transmission
hyd	Hydraulic	*turb*	Turbine
i	Iteration	*w*	Seawater
in	Inlet	*WF*	Working fluid
L	Loss	*WW*	Warm surface seawater

1. Introduction

Ocean Thermal Energy Conversion (OTEC) is an emerging renewable energy technology that uses the heat stored in the ocean to produce electricity. Besides OTEC's massive global technical potential of up to 9.3 TW [293], benefits over other renewables like solar PV include minimal land use and its baseload character [294]. Despite this, OTEC still lingers in an early development stage and has not been deployed commercially, yet. One of OTEC's development barriers is its *Capital Expenses (CAPEX)*, which are currently highly uncertain due to lack of data and experience [295]. This might explain why the existing global OTEC resource potentials reviewed below omit economic aspects and mostly pertain to the theoretical and technical level.

As reviewed by Liu et al. [296], the most extensive academic work on global OTEC resources has been generated by Nihous et al. Their initial estimation of 3 TW [297] was continuously refined, amongst others with 1° × 1° grid rasterization [298], geographical constraints like distance to coastline [299], and an ocean-atmosphere interface [293]. Using Nihous' [297] equation for OTEC's power density, Du et al. [300] found that OTEC's global technical potential might increase by 46% by the end of this century due to the impact of global warming. Other existing resource assessments are limited to regional and national levels, like the Aguni Basin [296], Barbados [301], and Malaysia [302]. Besides our earlier work on Indonesia [18], we are not aware of any OTEC resource assessments that directly incorporate OTEC's costs into the analysis. Moreover, the studies above only assess OTEC's nominal technical and economic performance, but not the performance under off-design conditions where warm and deep-sea water temperatures deviate from the nominal design values. This aspect has been addressed recently [303,304] showing that seasonal fluctuations in ocean thermal energy resources have a significant impact on the plants' technical and economic performance and thus need to be considered during the design stage. However, both studies used proprietary software and/or data and applied their models on individual plants, but not entire regions. Therefore, it is not clear yet whether their findings apply globally or only locally given the site-specificness of seawater temperature variations.

Against this background, we present a novel Python-based, open-source model, called pyOTEC, which sizes OTEC plants for best economic performance considering spatially and temporally varying ocean thermal energy resources. Using one year of daily seawater temperature data in 1/12° × 1/12° (≈ 9 km × 9 km) resolution, we apply pyOTEC to more than 100 countries and territories and calculate more than 150,000 OTEC plants filtered for site selection criteria like water depth, marine protected areas, and exclusive economic zones. Moreover, we check our findings with a sensitivity analysis for key technical and economic inputs. This study contributes to the academic body of literature in four ways. First, we provide the first estimation of OTEC's global *economic* potential. Second, this study underlines the significance of spatially and temporally resolved resource data when sizing OTEC plants. Third, we validate the findings of earlier off-design analyses for the entire world and deduce global guidelines for economic OTEC plant sizing. Fourth, pyOTEC delivers spatially explicit time series data on OTEC's net power production, which can be fed to energy system optimisation models like PyPSA [22] and Calliope [23]. With these models, OTEC's role in the global energy transition could be assessed from a system perspective, which is currently unexplored.

The remainder of the chapter is structured as follows. Section 2 shows the methods and materials developed and used in this study. Section 3 presents and discusses the findings from our global analysis, followed by conclusions in section 4.

2. Methods and materials

2.1. Theoretical background and overview

Here, we provide the theoretical background for readers unfamiliar with OTEC and a brief overview of the used methods and materials.

OTEC plants are thermal power plants that use warm surface seawater as a heat source and cold deep-sea water as a heat sink. There are many types of OTEC concepts [294]. Here, however, we only focus on closed-cycle, floating, moored systems. We do not consider onshore OTEC given the differences in plant siting, operations (e.g. water ducting) and cost structure. Nevertheless, we plan to expand pyOTEC for onshore systems in the future.

Following the saturated Rankine cycle, a liquid working fluid (here ammonia) is pumped to the evaporator, where it is fully evaporated using the heat of the surface seawater pumped into the system via seawater pumps. Then, the vapour expands and transfers its energy to the turbine, which drives a generator to produce electricity. The working fluid is fully condensed using cold seawater pumped from the deep-sea to the surface. The liquefied fluid flows back to the working fluid pump and the cycle starts anew. All auxiliary equipment, like seawater pumps, are powered by the electricity from the generator. The remaining net power is transmitted from the offshore power plant to the electricity grid onshore via sub-sea cables.

The methods and materials used in this study are visualised in Figure 43. First, we perform a site selection analysis, during which we remove sites unsuitable for OTEC. Once the user provides the region of interest, pyOTEC downloads the time series data for surface and deep-sea water temperature [48]. With these temperature profiles, pyOTEC assesses possible design configurations and for each technically feasible site returns the design with the lowest *Levelised Cost of Electricity (LCOE)* based on a nominal and off-design analysis.

In the following sub sections, we describe these steps in more detail.

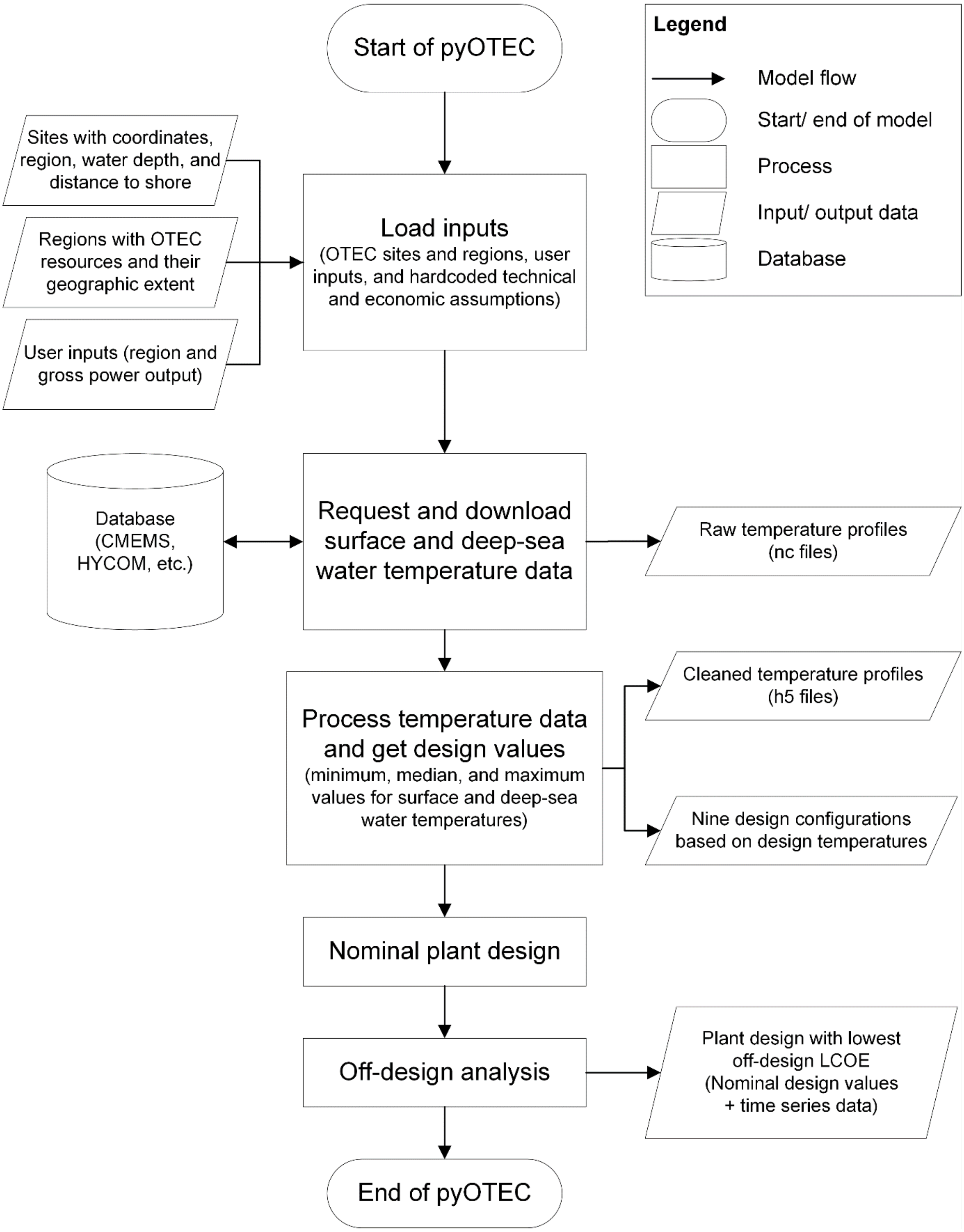


Figure 43. Flowchart of the pyOTEC model.

2.2. Site selection analysis

This sub section is mostly based on our earlier work [18], which we briefly summarise in Box II at the end of this sub section. We use the open-source software QGIS 3.18 Zürich [305] and datasets listed in Table 24.

First, we span a grid of points across the entire world within a latitude range of 30°N and 30°S [294]. This range ensures a sufficient temperature difference between surface and deep-sea water of ≥ 20 °C for net positive power production, i.e. power production exceeding seawater pumping power. The points have the same coordinates and spatial resolution (≈ 9 km × 9 km) as the seawater temperature data to be downloaded later and each point represents one plant. Next, we remove any points that are outside of the regions' exclusive economic zones [111] considering legal reasons pertaining to the economic use of marine space, but also to ensure a technically and economically feasible distance from plant to shore [299]. We further remove any points that are inside marine protected areas [306–309]. Moreover, we filter the sites for water depths outside 600–3,000 m [310]. The lower end ensures the extraction of sufficiently cold deep-sea water [311], while the upper range accounts for the technical limitations of mooring lines. The remaining sites are considered technically feasible for OTEC. Next, we calculate the distance of each site to the closest coastline [305] to compute the transmission costs and losses later.

Lastly, we calculate the geographic extent of all regions with technically feasible OTEC sites. We store the names of the regions as well as their coordinates in a csv file. This file will be used to download the seawater temperature data as described in the next section. Moreover, we create another csv file that stores all technically feasible OTEC sites (N = 218,481 sites), including their coordinates, region, water depth, and distance to shore. Both csv files are stored in pyOTEC's data inventory and are loaded once the program is initiated.

Table 24. Datasets and criteria used for the site selection analysis.

Layer	Criterion	Dataset reference	Layer type	Spatial resolution
Climatic zone	30°N–30°S	-	-	-
Exclusive economic zones	Sites must be inside them	[111]	Vector	-
Marine protected areas	Sites must be outside of them	[306–309]	Vector	-
Water depth	600–3,000 m	[310]	Raster	≈ 500 m × 500 m
World map	-	[305]	Vector	-

Box II

In our first original article on OTEC potentials [18], we laid out the basic workflow for the geospatial mapping of technical and economic OTEC potentials. In that study, we did not use the exclusive economic zones, but the provincial marine borders, as the areas within which OTEC plants may be implemented. We did already use spatially and temporally ocean resource data (HYCOM) as input data, but we did not yet model the power plants and their variations in power output. Instead, we assumed the plants to be black boxes and derived their costs from existing literature (for our critical literature review on OTEC economics, see Ref [294]). The costs account for the effects of economies of scale, but not yet technological learning, which we tackled in a follow-up study, see Box III.

The technically feasible sites for OTEC are shown in Figure 44. If each site hosts one 100 MW_{net} plant, the total technical potential amounts to 102.1 GW_{net}, producing 817 TWh/year assuming an availability of 8,000 hours per year. Using the lower range of costs from literature and electricity tariff at the time, the economic potential is 2 GW_{net} and 16 TWh/year, respectively.

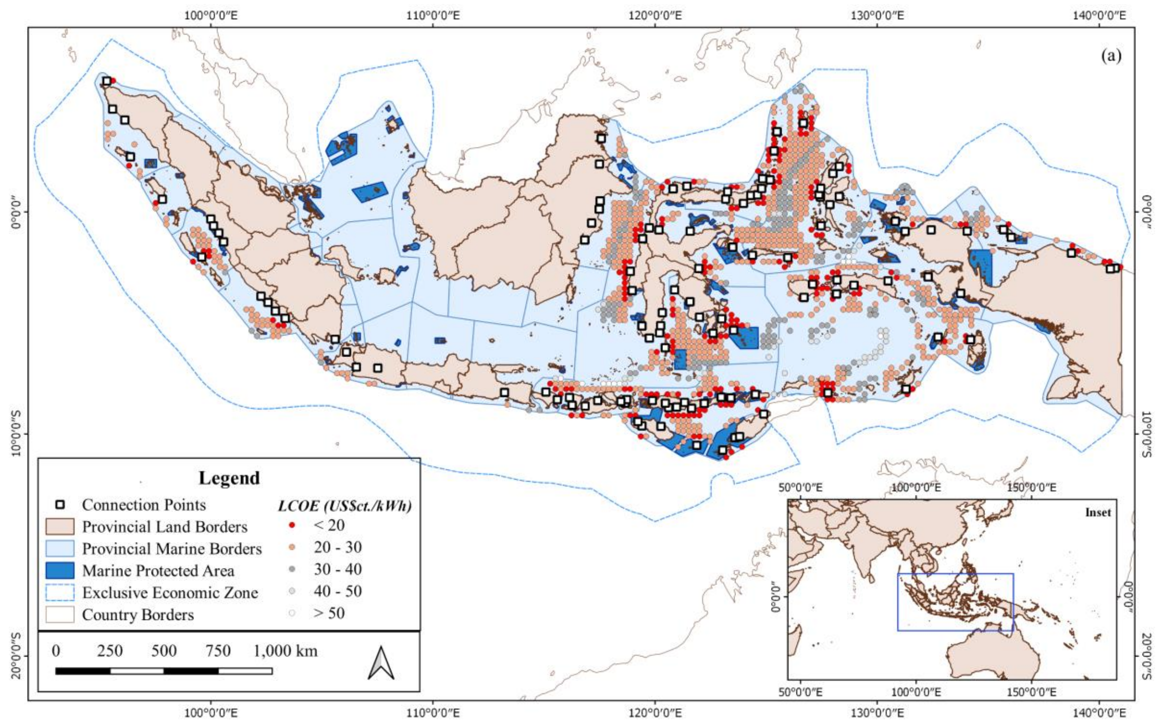


Figure 44. Technically feasible OTEC sites within Indonesia's provincial marine borders. The levelised cost of electricity at each site was calculated using the lower range of costs from OTEC economics literature. Illustration taken from Langer et al. [18].

2.3. The pyOTEC modelling framework

2.3.1. Seawater temperature data

After setting up pyOTEC (see Appendix L), the user is asked for the region and plant size to be analysed. Once these are provided, pyOTEC requests and downloads the time series data for surface and deep-sea water temperature. Here, we use the Global Ocean Physics Reanalysis by Copernicus Marine Service [48], which offers global ocean data in daily, i.e. 24 h, time steps from 1993–2020 in a spatial resolution of 1/12° × 1/12° (≈ 9 km × 9 km) across 50 depth layers.

pyOTEC does not download the entire global dataset, but only a part of it, called a subset. The horizontal spatial boundaries of the subset are given by the geographical extent of the analysed region. By default, pyOTEC only requests the seawater potential temperature for the full year 2020 at depths of 21.6 m and 1,062 m, which correspond to the length of the warm and cold seawater inlet pipes. The user can change these values in pyOTEC's parameter file. In this chapter, we size the plants for four different deep-sea layers (644 m, 763 m, 902 m, and 1,062 m) and select for each site the depth with the most economic plant design (i.e. lowest LCOE as described later).

Most likely due to the mismatch of spatial resolution between the seawater temperature and GEBCO bathymetric dataset (500 m × 500 m versus 9 km × 9 km), only 162,620 of the 218,481 sites mapped in section 2.2 contain seawater temperature data. These sites are used for the global analysis.

Before the OTEC plants are sized and analysed, the seawater temperature data is further processed, e.g. cleaned from outliers and NaN. We describe the data processing in more detail in Appendix M.

2.3.2. Nominal and off-design plant sizing

This sub section is based on our earlier off-design OTEC model [304], with all technical and economic equations being listed in Appendix N. For pyOTEC, we moved the model from proprietary MATLAB to publicly available Python, fixed bugs, and scaled the model from per-plant to per-region analysis. Earlier, the model calculated the plant's operation for each time step individually, whereas now pyOTEC performs elementwise arithmetic calculations on the entire time series data, which is significantly faster. Nonetheless, the underlying equations, assumptions, and system logics from our earlier work (ibid.) remain unchanged, so we summarise the workflow here and refer to the underlying paper for more information.

pyOTEC uses the cleaned seawater temperature data to calculate the site-specific minimum, median, and maximum surface and deep-sea water temperatures. These temperatures are used to perform a two-stage design process consisting of a nominal and off-design analysis using the technical assumptions listed in Table 25. All inputs are stored in one separate parameter file and can be changed by the user.

First, the OTEC plants are sized under nominal conditions, meaning that the plants are assumed to operate solely under design conditions without seasonal seawater temperature variations. The plants are designed using combinations of minimum, median, and maximum warm and cold seawater temperatures as inlet temperatures for the evaporator and condenser. We call these nine combinations of warm and cold inlet temperatures *configurations* as visualised in Figure 45. To determine the economically best nominal outlet temperatures, pyOTEC loops through 49 combinations of warm and cold seawater temperatures differences between inlet and outlet (from 2 °C to 5 °C in steps of 0.5 °C). For example, if the nominal warm and cold inlet temperatures are 28 °C and 4 °C, then the assessed nominal warm and cold outlet temperatures range between 23–26 °C (28 °C minus 5 °C and 28 °C minus 2 °C) and 6–9 °C (4 °C plus 2 °C and 4 °C plus 5 °C) in intervals of 0.5 °C.

Table 25. Technical assumptions for the nominal and off-design analysis. Except for the seawater inlet pipe lengths, all assumptions are directly taken from [304]*. Note that the pressure drop coefficient for evaporator and condenser was accidentally given as 120 in the earlier study (ibid.), although it should be 100. [-] refers to unitless parameters.*

Parameter	Assumption	Reference(s)
Density liquid ammonia [kg/m^3]	625	
Spec heat capacity seawater [kJ/kgK]	4.0	[312]
Density surface seawater [kg/m^3]	1,024	[313]
Density deep seawater [kg/m^3]	1,027	[313]
Pinch-point temperature difference evaporator and condenser [K]	1.0	[314,315]
Nom overall heat transfer coefficient evaporator [kW/m^{2}K]	4.5	[303,316]
Nom overall heat transfer coefficient condenser [kW/m^{2}K]	3.5	[303,317]
Isentropic efficiency turbine [%]	82	[311]
Mech efficiency turbine [%]	95	[311,318]
Electrical efficiency generator [%]	95	[311,318]
Hydraulic efficiency seawater pump [%]	80	[303,311]
Electric efficiency seawater pump [%]	95	[303]
Mech efficiency ammonia pump [%]	95	[303]
Isentropic efficiency ammonia pump [%]	80	[311]
Default length inlet WW pipe [m]	21.6	
Default length inlet CW pipe [m]	1,062	
Length outlet WW and CW pipe [m]	60	
Pipe thickness [m]	0.09	[319,320]
Density HDPE [kg/m^3]	995	[320]
Roughness factor *z* [mm]	0.0053	[311]
Pressure drop coefficient evaporator & condenser [-]	100	
Nominal flow velocity in the pipes [m/s]	2.0	[294,316]
Nominal flow velocity in the heat exchangers [m/s]	1.0	[316]
Maximum inner pipe diameter [m]	8	

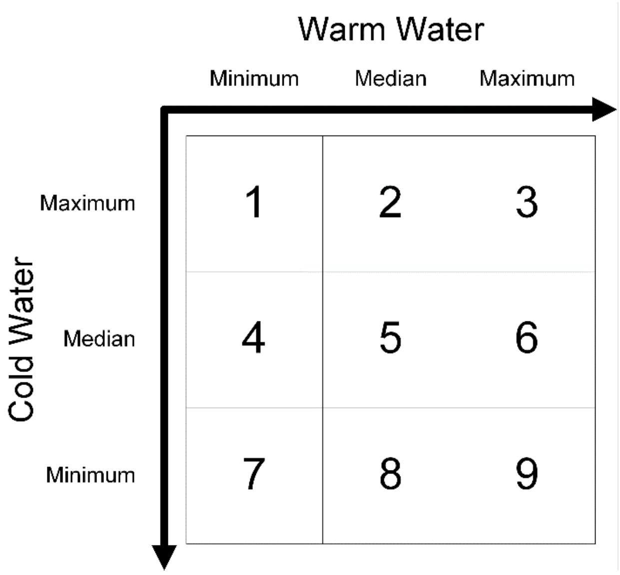


Figure 45. The nine configurations analysed by pyOTEC (modified illustration from Langer et al. [304]*). Configuration 1 is the most conservative design based on worst-case temperature values, whereas configuration 9 is the most optimistic design using best-case temperature values.*

For all inlet and outlet temperature combinations, pyOTEC deploys the following workflow. Using the outlet temperatures and pinch-point temperatures, pyOTEC calculates the nominal saturation pressures and temperatures of the working fluid in the evaporator and condenser. With these and the gross turbine work $\dot{W}_{t,gross}$ provided by the user (entered as a negative number according to IUPAC sign convention), the enthalpies, working fluid and seawater mass flows, as well as heat flows and working fluid pump work are calculated. Next, the evaporator and condenser are sized using Eq. (1), where $\dot{Q}_{HX}$ is the heat flow, U_{HX} is the overall heat transfer coefficient, and $\Delta T_{log,HX}$ is the logarithmic mean temperature difference of the heat exchanger *HX*.

$$A_{HX} = \frac{|\dot{Q}_{HX}|}{U_{HX} * \Delta T_{log,HX}} \tag{1}$$

Next, the seawater pipes and pumps are sized. The number and inner diameter of the pipes of the warm and cold system side are calculated such that the maximum allowed inner diameter (default: 8 m) and pressure drop (default: 100 kPa) are not exceeded, mainly by tuning the nominal seawater velocity. We assume that the warm and cold seawater mass flows are distributed evenly across their respective warm and cold seawater pipes. The total pressure drop in the warm and cold system side is calculated using Eq. (2), where Δp_w is the total pressure drop, $f_{D,w}$ is the Darcy friction factor, ρ_w is the seawater density, $l_{pipe,w}$ and $d_{pipe,w}$ are the total length and inner diameter of the pipes, $v_{pipe,w}$ and $v_{HX,w}$ are the velocities in the pipes and heat exchanger, respectively, and $K_{L,w}$ is the pressure drop coefficient for the heat exchanger *HX*. Index *w* distinguishes the warm and cold system side.

$$\Delta p_w = \rho_w * \left(f_{D,w} * \frac{l_{pipe,w}}{d_{pipe,w}} * \frac{v_{pipe,w}^2}{2} + K_{L,w} * \frac{v_{HX,w}^2}{2} \right) \tag{2}$$

The required seawater pump work $\dot{W}_{t,pump,w}$ per system side *w* is calculated with Eq. (3), using the seawater mass flow $\dot{m}_w$ and the hydraulic and electric seawater pump efficiencies $\eta_{pump,hyd}$ and $\eta_{pump,el}$.

$$\dot{W}_{t,pump,w} = \frac{\dot{m}_w * \Delta p_w}{\rho_w * \eta_{pump,hyd} * \eta_{pump,el}} \tag{3}$$

The net power at shore $\dot{W}_{t,net}$ is computed with Eq. (4), where $\eta_{turb,mech}$ and $\eta_{turb,el}$ are the mechanical and electric turbine efficiency, $\dot{W}_{t,pump}$ is the pumping power of the cold and warm system side *CW* and *WW* as well as the working fluid *WF*, and the power transmission efficiency from floating OTEC plant to shore η_{trans}. Note that the work flows are aggregated because the turbine work has a negative sign, while the pump works have positive signs following the IUPAC sign convention.

$$\dot{W}_{t,net} = \frac{\dot{W}_{t,gross} * \eta_{turb,mech} * \eta_{turb,el} + \dot{W}_{t,pump,CW} + \dot{W}_{t,pump,WW} + \dot{W}_{t,pump,WF}}{\eta_{trans}} \tag{4}$$

With the plants being sized, pyOTEC calculates the component *Capital Expenses (CAPEX)* using the economic assumptions in Table 26. OTEC's strong economies of scale are accounted for with Eq. (5). Where applicable, the specific component cost *capex* of a plant with the user-defined size $\dot{W}_{t,gross}$ are scaled against a reference plant of size $\dot{W}_{t,gross,0}$, component cost $capex_0$ and scaling exponent *b*. The user can select between *low-cost* and *high-cost* assumptions reflecting the high uncertainty of OTEC's cost [295]. By default, pyOTEC uses the low-cost assumptions and the results presented here pertain to them.

$$capex = capex_0 * \left(\frac{\dot{W}_{t,gross,0}}{\dot{W}_{t,gross}} \right)^b \tag{5}$$

Table 26. Low-cost economic assumptions taken from Langer et al. [304] *used in this study. The variable D for power transmission costs refers to the distance from the OTEC plant to the closest coastline. All costs are displayed in US$(2021) values.*

Cost component	Specific reference cost $capex_0$ [Ref]	Scaling exponent *b* [-]	Reference gross power $P_{gross,0}$ [MW]	References
Turbine [US$/$kW_{gross}$]	328	0.16	136	[317,320]
Heat exchangers [US$/$m^2$]	226	0.16	80	[122,313,320]
Pumps [US$/$kW_{pump}$]	1,674	0.38	5.6	[122,313]
Seawater pipes [US$/$kg_{pipe}$]	9	-	-	[316,320]
Power transmission [US$/$kW_{gross}$]	$10.3 * D + 68.7$	-	-	[17]
Design & management [US$/$kW_{gross}$]	3,113	0.70	4.0	[316,317]
Structure & mooring [US$/$kW_{gross}$]	4,465	0.35	28.1	[313,317]
Deployment [US$/$kW_{gross}$]	650	-	-	[317]
Extra costs [% of CAPEX]	5	-	-	[320]
OPEX [% of CAPEX/year]	3	-	-	[122]
Project lifetime *n* [years]	30			[295]
Discount rate *r* [%]	10			[18]
Availability factor a_f [%]	91.3			[316,321]

After summing up all component CAPEX to form the total system CAPEX, we move to the *Levelised Cost of Electricity (LCOE)*, which reflects the costs of electricity generation considering all costs in their present value accruing over the plant's lifetime. First, we calculate the *Capital Recovery Factor (CRF)* with Eq. (6) to annualise the total system CAPEX, using the discount rate *r* and useful lifetime *n*. The LCOE is computed with Eq. (7), using CRF, total system CAPEX, *Operational Expenses (OPEX)*, net power $\dot{W}_{t,net}$, and the availability factor a_f reflecting how long the plant operates per year after planned and unplanned downtime.

$$CRF = \frac{r * (1+r)^n}{(1+r)^n - 1} \tag{6}$$

$$LCOE = \frac{CAPEX * CRF + OPEX}{\dot{W}_{t,net} * a_f * 8{,}760 \frac{hours}{year}} \tag{7}$$

The output of Eq. (7) is the nominal LCOE, which assumes that the nominal design conditions, including seawater temperatures, apply continuously throughout the plants' lifetime. The nominal LCOE is calculated for each of the possible 49 outlet temperature combinations in order to find the plant design with the lowest nominal LCOE. That design, together with its properties, e.g. heat exchanger areas, are passed to the off-design analysis module.

The goal of the off-design analysis is to find the configuration from Figure 45 with the lowest LCOE considering the seasonal variations of warm and cold ocean thermal energy resources. The major difference between the nominal and off-design analysis is that the latter does not use nominal temperatures, but time series data, which is mostly not equal to the nominal temperatures. Hence, there can be a lack and/or excess of warm and/or cold ocean thermal energy resources.

To account for these situations, we use the sliding pressure control logic from our earlier model [304]. With this logic, the evaporation pressure is decreased if the warm seawater temperature is below the nominal temperature; and the condensation pressure is increased if the cold seawater temperature is above the nominal temperature. If there is an excess of warm and/or cold ocean thermal energy resources, the evaporation and/or condensation pressures are kept at nominal values, and instead the seawater mass flows are decreased, as less seawater is required to evaporate/condense the same amount of working fluid. The (adjusted) saturation pressures and temperatures as well as enthalpies at each process stage are calculated with the same equations as for the nominal analysis.

In case of excess, pyOTEC accounts for the off-design behaviour of the heat exchangers using Eqs. (8–12). There, the Number of Transfer Unit *NTU*, effectiveness ε_{HX} (assuming single-flow heat exchange), outlet temperature $T_{w,out}$, seawater mass flow $\dot{m}_{w,}$ and overall heat transfer coefficient U_{HX} are solved iteratively over *i* iterations for heat exchanger *HX* and system side *w*. Assuming plate heat exchangers, the scaling exponent for U_{HX} against the nominal values *nom* is 0.65 [314].

$$NTU_{HX,i} = \frac{U_{HX,i} * A_{HX}}{\dot{m}_{w,i} * c_p} \tag{8}$$

$$\varepsilon_{HX,i} = 1 - e^{-NTU_{HX,i}} \tag{9}$$

$$T_{w,out,i} = \begin{cases} T_{w,in} - \varepsilon_{HX,i} * \left(T_{w,in} - T_{evap}\right) \; if \; evaporator \\ T_{w,in} + \varepsilon_{HX,i} * \left(T_{cond} - T_{w,in}\right) \; if \; condenser \end{cases} \tag{10}$$

$$\dot{m}_{w,i+1} = \frac{-\dot{Q}_{HX}}{c_p * \left(T_{w,out} - T_{w,in}\right)} \tag{11}$$

$$U_{HX,i+1} = U_{HX,nom} * \left(\frac{\dot{m}_{w,i+1}}{\dot{m}_{w,nom}}\right)^{0.65} \tag{12}$$

$$repeat \; until \left|\left(T_{w,i+1} - T_{w,i}\right)\right| < 1E^{-7}$$

$$for \; i = 0 \rightarrow \; U_{HX,i} = U_{HX,nom} \; and \; \dot{m}_{w,i} = \dot{m}_{w,nom}$$

For the system pressure drop Δp_w, seawater pumping power $\dot{W}_{t,pump,w}$, and net power $\dot{W}_{t,net}$, we again use Eqs.(2–4), but this time with the time series data as inputs.

The off-design LCOEs per configuration are calculated using Eq. (7), this time using the average net power output throughout the modelled time span. After the nominal and off-design analyses are conducted for all nine configurations, pyOTEC returns the configuration with the lowest off-design LCOE.

2.4. Global analysis and sensitivity analysis

To test the model and showcase its usefulness, we apply pyOTEC to all countries and territories with technically feasible OTEC sites and available electricity demand data. To assure an adequate size of the plants in relation to electricity demand, we calculate the plant size by dividing the regions' 2019 net electricity consumption [322 n.d.] by 8,760 hours per year. The maximum plant size is capped at 136 MW_{gross}, which represents OTEC at full commercial size with limited further economies of scales [294]. The index 'gross' refers to the power output of the turbine excluding losses and the power consumption of auxiliary equipment. If the electricity demand of a region is not listed, the region is omitted from the analysis.

The approach above is strongly simplified and merely yields an order-of-magnitude estimation of OTEC's global economic potential. With this approach, we disregard demand covered by existing and future competing power generation technologies. Therefore, regions highlighted as relevant in this study should be further investigated with more localised and refined data.

Furthermore, we perform a sensitivity analysis to consolidate the key findings of this study. We change each key technical and economic parameter by +/- 30% (where possible) and record the changes in LCOE and configuration. Since this analysis comprises dozens of re-runs, we perform the analysis only for Indonesia, which we deem as representative given the country's diversity of ocean thermal energy resources.

2.5. Methodological limitations

This section discusses the four main limitations of pyOTEC. First, the model's scope is currently limited to floating, closed-cycle OTEC using plate heat exchangers and ammonia as working fluid. Alternative concepts (e.g. open-cycle OTEC as well as Kalina and Uehara cycle), technologies, and working fluids are consequently omitted. Second, the plants' operation is simplified as we neglect aspects like heat transfer in the seawater pipes and pumps as well as deteriorating system performance due to biofouling. Regarding plant spacing, we do not consider location-specific limitations like the availability of cold deep-sea water from global ocean currents [323] and other uses of marine space, like shipping. Third, although economically feasible systems can be designed with pyOTEC, the results are not optimised as optimal configurations do not necessarily pertain to minimum, median, or maximum values. This limitation could be addressed with an interpolation map, which we did not do here to limit computational costs of the global analysis. Fourth, pyOTEC's economic model is based on current knowledge of OTEC economics, which is limited due to the technology's early development stage.

All these limitations considered, there are ample fields of development for pyOTEC, and we hope that this study motivates other OTEC researchers to participate in the model's improvement. Regardless, the abovementioned limitations do not diminish the model's usefulness as a pre-feasibility study tool.

3. Results and discussion

3.1. Global OTEC resources and their LCOEs

Figure 46 shows all technically feasible OTEC sites and their LCOEs. Economically interesting sites with LCOEs below 17.6 US¢(2021)/kWh are mostly situated along the equator in South-East Asia and South America. At higher latitudes, LCOEs increase due to fewer ocean thermal energy resources and higher seasonal variability. Some sub-tropical regions in the Caribbean Sea and Asia are exceptions with LCOE below 17.6 US¢(2021)/kWh as well. In Africa, East Asia, and Australia, LCOEs tend to be higher, either due to small plant sizes with lower economies of scale (e.g. Liberia), comparatively low surface seawater temperatures (e.g. in Australia), or high deep-sea water temperatures (e.g. in India). Nonetheless, interesting cases for large-scale OTEC with LCOE below 20 US¢(2021)/kWh can still be found in India and Africa (e.g. in Nigeria).

Out of the 162,620 analysed sites, 81% yielded the lowest LCOE at a deep-sea water intake of 1,062 m. A longer cold water pipe increases pipe costs and pumping power. However, the lower deep-seawater temperatures allow for fewer cold water pipes with smaller diameters as less water is required to condense the same amount of working fluid. Together with the downsizing of other cold-side components, like condenser, the benefits of deeper cold water intake outweigh the drawbacks in our model.

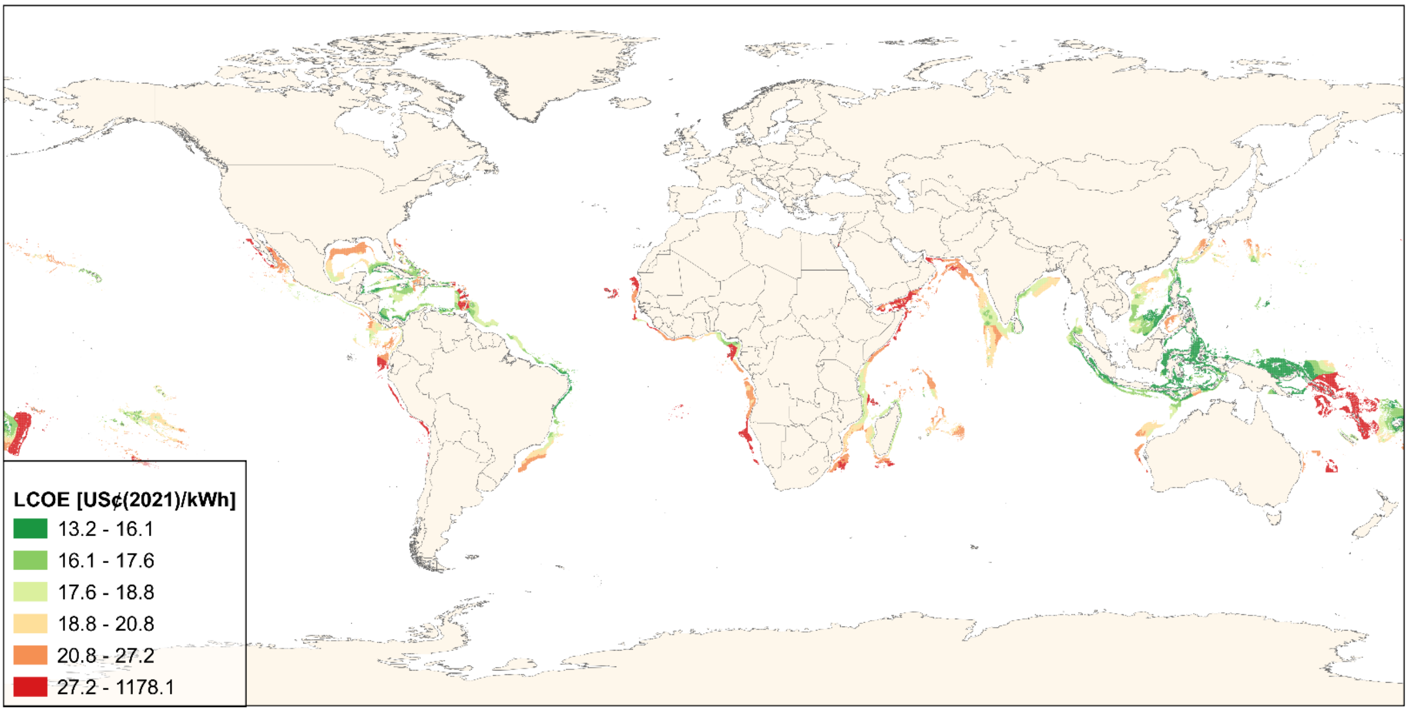


Figure 46. OTEC sites (N = 162,620 sites) across the world and their LCOEs.

Table 27 shows the 20 regions with largest technical potential for OTEC and their 2019 electricity demand coverage. The technical potential depends on the system size, available marine area suitable for OTEC, plant spacing, and warm and cold ocean thermal energy resources. For most regions, there is a mismatch between OTEC supply and electricity demand, with regions where supply exceeds demand by a manifold, like Fiji, and regions where OTEC could only meet parts of demand, e.g. in China and the United States. If OTEC's economic potential is limited by 2019 demand, only 11 PWh/year of the global technical potential of 107 PWh/year would be tapped economically unless future grid expansions allow for the long-distance transport of OTEC power across land and sea.

Note though that the technical potential of 107 PWh/year does not reflect how much OTEC could and should be implemented in practice. First, such a level of deployment might entail significant environmental impacts on local ecosystems, e.g. via ocean thermal degradation. With a simplified uniform plant spacing of 9 km × 9 km, we disregard the location-specific availability of cold deep-sea water from global ocean currents, which might necessitate a further spacing of plants [323]. Other environmental pressures by OTEC include the relocation of toxic materials as well as entrainment (i.e. organisms entering the water intake) and impingement (i.e. organisms being caught at screening structures at the water intake) [324]. Second, there might also be negative economic implications, e.g. from the adjustment of shipping routes to avoid collisions between ships and OTEC plants. Then again, such widespread implementation would not be necessary in most regions. Countries like Fiji could meet their electricity demand with a single OTEC plant, which would only require 0.006% of available marine area. Even large countries like Indonesia would only need 0.4% of available marine area to fully meet their 2019 electricity demand. Hence, we would expect OTEC's environmental impact to be moderate in such regions. In countries like China and the United States, where the technical OTEC potential is less than demand, we would see OTEC more as a complimentary technology to other renewables (see section 3.2).

Table 27. The 20 regions with the largest OTEC resources and their potential to cover 2019 net electricity consumption. The countries and regions are ordered by descending total OTEC electricity generation. "Total marine area" for the world refers to the marine areas (i.e. exclusive economic zones) of countries and territories with OTEC resources. "Marine area occupied by OTEC" does not refer to the area of the floating OTEC platform, but the assumed spacing of 9 km × 9 km between plants.

Region	Total technical OTEC potential [TWh/year]	System size per plant [MW_{gross}]	Net electricity consumption in 2019 [TWh]	Economic potential [TWh/year] if capped by		Total marine area [10^3 km^2]	Marine area occupied by OTEC [10^3 km^2] and [%]	Electricity generation density [GWh/km^2]	Warm seawater temperatures [°C]			Cold seawater temperatures [°C]		
				2019 demand	Two times 2019 demand				Min	Med	Max	Min	Med	Max
Indonesia	14,119	136	255	255	509	6,029	1,357 (22%)	10.41	21.1	29.3	31.7	2.3	4.6	13.4
Papua New Guinea	8,980	136	4.1	4.1	8.3	2,403	860 (36%)	10.44	24.8	30.1	31.6	3.1	4.2	7.7
India	7,437	136	1,342	1,342	2,684	1,660	753 (45%)	9.88	23.8	29.2	31.6	4.6	7.2	11.7
Fiji	6,382	120	1.1	1.1	2.1	1,284	714 (56%)	8.94	21	27.5	30.8	2.8	3.8	7.8
Brazil	5,142	136	538	538	1,076	3,208	521 (16%)	9.87	18.5	26	30.1	2.9	3.9	8.1
Philippines	4,208	136	96	96	192	1,974	412 (21%)	10.21	22.8	29.3	31.9	2.1	4.2	10.9
Mexico	3,853	136	279	279	558	3,181	444 (14%)	8.69	12.5	26.5	32.2	3.6	4.7	8.6
Japan	3,396	136	945	945	1,890	4,065	368 (9%)	9.22	18.8	25.6	31.5	2.5	3.7	8.7
United States	3,286	136	3,989	3,286	3,286	2,450	372 (15%)	8.84	18.2	26	31	3.1	4.8	14.6
Mozambique	3,158	136	13.5	13.5	26.9	567	318 (56%)	9.94	19.7	26.9	30.7	2.9	5.9	12.1
Australia	3,116	136	239	239	477	6,866	343 (5%)	9.09	17.1	26.6	31.8	3.4	4.9	8.6
Madagascar	2,854	136	1.9	1.9	3.8	1,194	295 (25%)	9.67	19.4	26.9	31.6	2.4	5.5	12.5
French Polynesia	2,656	73	0.64	0.64	1.3	4,772	498 (10%)	5.33	18.5	27.7	30	3.2	4	6.7
Vietnam	2,289	136	213	213	426	751	227 (30%)	10.09	22.9	28.7	31.5	3.6	4.1	7.4
Republic of Mauritius	2,077	136	2.9	2.9	5.8	1,279	215 (17%)	9.65	21.7	26.2	30.5	4.1	5	9.7
China	1,959	136	6,803	1,959	1,959	1,307	196 (15%)	9.99	22.9	27.8	31.4	3.5	4.1	6.8
Costa Rica	1,792	136	10	10	20	590	187 (32%)	9.60	15.3	26.8	30.7	3.4	4.5	7.4
Jamaica	1,603	136	3.1	3.1	6.2	272	159 (59%)	10.06	26.5	28.4	30.6	4.4	5	10
Colombia	1,532	136	74	74	148	718	167 (23%)	9.15	14.2	27.3	30.5	3.9	4.9	8.8
Maldives	1,511	70	0.62	0.62	1.2	921	289 (31%)	5.24	27	29.3	31.4	5	6.6	10.8
World	**107,012**	**-**	**23,921**	**10,974**	**16,222**	**105,702**	**13,172 (11.9%)**	**8.1**	**-**	**-**	**-**	**-**	**-**	**-**

Figure 48 shows the lowest LCOE per region and the electricity production of the corresponding plants. The LCOE is not only tied to resource availability, but also plant size given OTEC's economies of scale. Our results show that LCOEs below 20 US¢(2021)/kWh are possible at plant sizes as small as 44 MW_{gross} (Haiti). As shown in the bottom part of Figure 48, LCOEs below 15 US¢(2021)/kWh are achieved in 15 regions at system sizes ≥ 120 MW_{gross}. Therefore, OTEC at full scale could be an economically attractive alternative to other renewables in high-demand countries, especially considering further cost reductions via global technological learning as shown in Box III [19].

Box III

As a follow-up to Ref. [18] in Box II, we investigated the effect of technological learning on OTEC's economic potential [19]. We developed an upscaling model that implements OTEC at a fixed annual rate to meet local demand. As implementation progresses, OTEC plants become larger and cheaper by a learning rate, thus reflecting the cost-reducing effects of economies of scale and technological learning.

OTEC's economic potential increases substantially if costs decline as currently projected. After being scaled from 10 to 100 MW_{net}, OTEC's levelised cost of electricity could decline from 50.7 to 6.2 US¢(2018)/kWh. Figure 47 displays how OTEC is first mainly deployed in East Indonesia, where high local tariffs curb the losses from yet unprofitable pioneer plants. Once profitable, full-scale OTEC spreads to the rest of the country. Compared to other technologies, OTEC's required learning rate is relatively low. But to reach full scale by 2050, OTEC would need to be scaled up at a rate comparable to those of solar PV and wind power, which would require sustained global support and commitment.

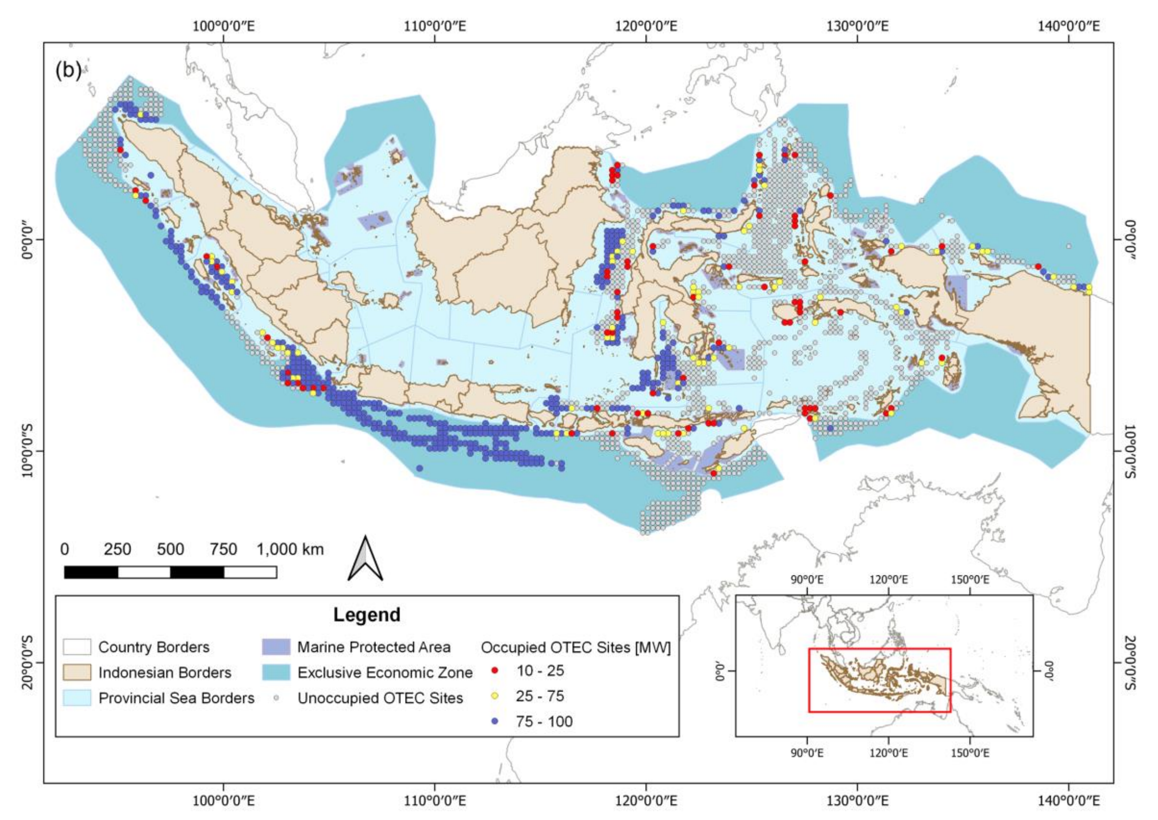


Figure 47. Implementation of OTEC in Indonesia throughout the upscaling to full commercial scale [19].

Then again, there are many cases where large-scale OTEC is neither economically sensible or necessary. Upscaling only marginally improves OTEC's economic feasibility if local ocean thermal energy resources are generally low. Good examples are Egypt and Saudi Arabia, where the minimum LCOEs of 136 MW_{gross} systems are 125 and 121 US¢(2021)/kWh, respectively. Moreover, full-scale OTEC might not be necessary for small island developing states. There, electricity demand is too low for such systems; and high electricity generation costs might allow smaller systems to be economic. For example, the 7.1 MW_{gross} systems in Tonga can have LCOEs as low as 36.4 US¢(2021)/kWh, which is significantly lower than the estimated total generation cost of more than 100 US¢(2016)/kWh in the off-grid parts of the island [325]. Hence, OTEC's path towards commercialisation and full scale could begin at such island states, which would benefit from a stable, clean, and cheaper electricity supply.

Figure 49 shows how the LCOE can vary within the analysed regions. While the variations are rather small in Grenada, Haiti, and the Maldives, they are considerable in Indonesia, Japan, and the United States. This can mainly be explained by the extent of the regions. The marine area of Grenada, for example, is comparatively small, so ocean thermal energy resources and the distance from OTEC plant to shore are relatively uniform. In contrast, countries like Indonesia and United States stretch over thousands of kilometres, so ocean thermal energy resources can be quite diverse. These things considered, one must be aware of the potentially significant fluctuations of LCOE.

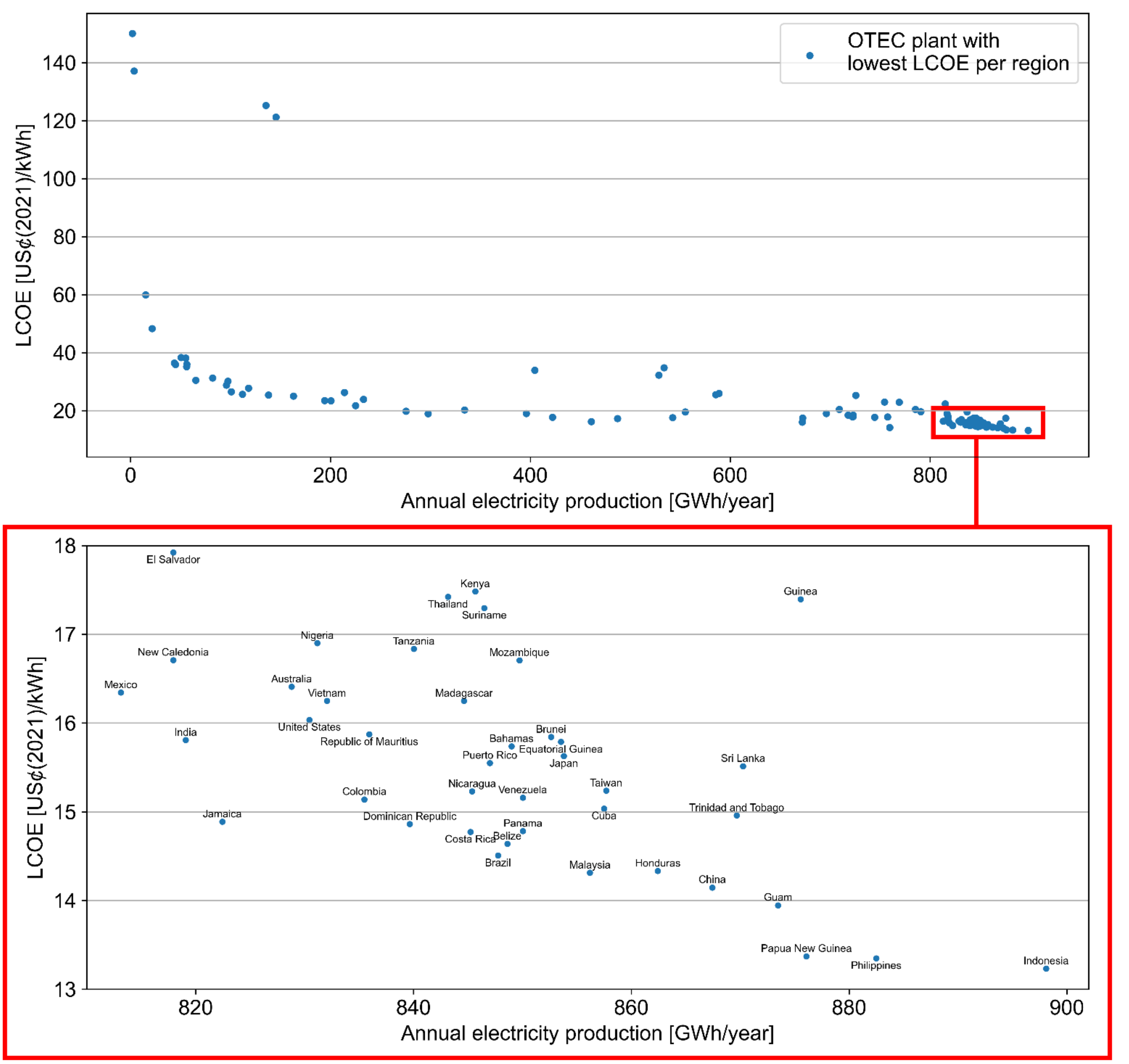


Figure 48. The OTEC plants with the lowest off-design LCOE per region and their respective annual electricity production. The bottom portion of the figure (red frame) zooms onto a set of interesting countries and territories with LCOE < 18 US¢(2021)/kWh and annual electricity production > 800 GWh/year.

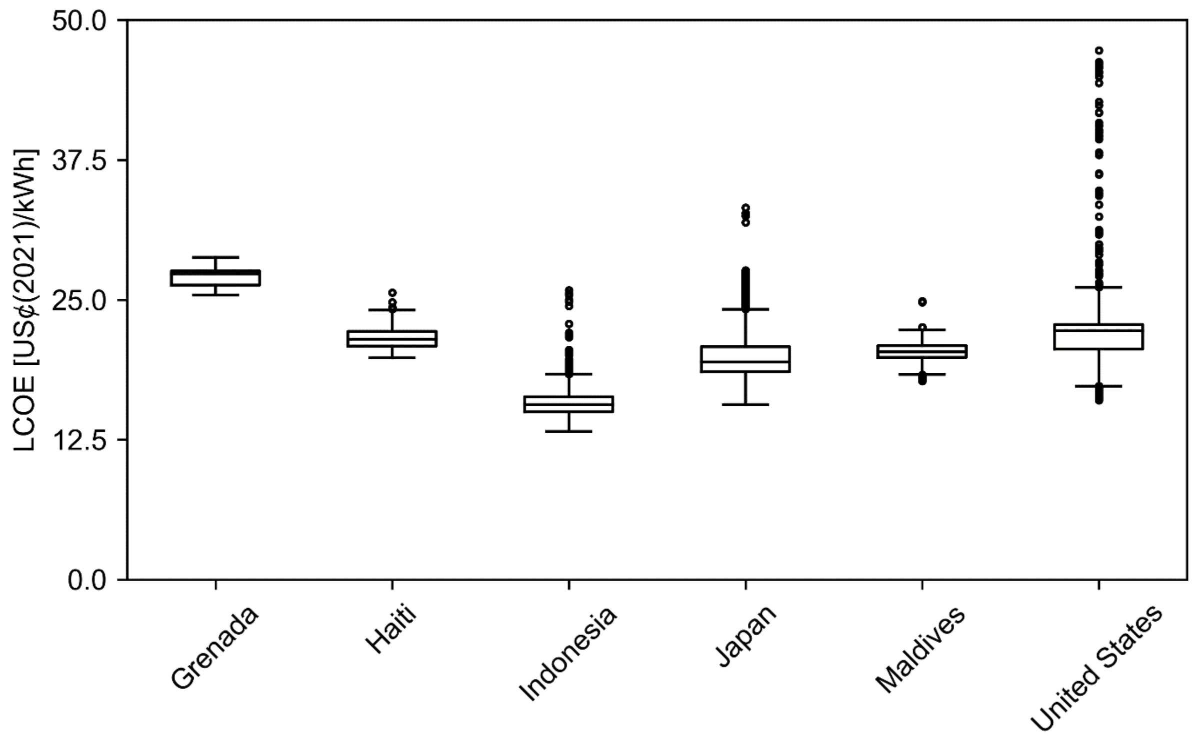


Figure 49. Box and whisker plots showing ranges of LCOE across selected countries and system sizes (Grenada: 22 MWgross, Haiti: 44 MWgross, Maldives: 70 MWgross, rest 136 MWgross). Outliers are points outside 1.5 times the interquartile range.

3.2. OTEC's potential role against other renewables

In practice, OTEC's economic potential also depends on its competitiveness against other renewables. According to IRENA [290], all major renewable energy technologies except concentrated solar power reached global weighted LCOE ≤ 7.5 US¢(2021)/kWh in 2021 (i.e. bioenergy, geothermal, hydropower, solar PV, and onshore and offshore wind). Regarding other ocean energies, IRENA [326] reports current LCOEs of 20–45 US¢/kWh for tidal energy and 30–55 US¢/kWh for wave energy, which are expected to decline to 11 US¢/kWh and 16.5 US¢/kWh, respectively, until 2030.

Unless costs decline substantially, OTEC would not be able to undercut its (more mature) competitors' costs. So, why should OTEC be considered if there are significantly cheaper and commercially available alternatives?

We believe that small island developing states and archipelagic states are the most interesting niches for OTEC. Especially the former are currently strongly dependent on expensive imported Diesel from volatile global markets [327]. Unless these islands have geothermal resources [328], their options for Diesel generator substitution with renewables are limited. Regarding bioenergy, fuel dependency would shift from Diesel to biofuels if imported, and domestically cultivated power crops would compete against food crops and other land uses [327]. The latter issue might also be relevant for hydropower, solar PV, and onshore wind. Regarding offshore wind, there are islands, like Sao Tome and Principe, where mean wind speeds are too low for an economic operation of currently available offshore wind turbines [47]. On islands with economic offshore wind and/or geothermal potentials, we see OTEC as a complimentary technology that diversifies the islands' electricity generation mix. Once developed towards maturity within these niches, OTEC might become an interesting technology for continental coastal states as well. There, OTEC could substitute the final bits of fossil-fuel-based power generation that would otherwise require large capacities of solar PV, wind power and/or energy storage. Moreover, OTEC could also be considered for its dispatchability, especially once the penetration of non-dispatchable renewables, like solar PV, increases.

Note that this discussion solely pertains to floating, closed-cycle OTEC. Further economic potentials could arise from onshore OTEC if there is trade-off between avoiding mooring and platform costs on the one side and increased pipe costs and pumping power on the other. Furthermore, there are plenty of other concepts and use cases discussed in literature, e.g. freshwater and power production via open-cycle OTEC [294], the production of e-fuels like hydrogen [329] or ammonia [317], or the enhancement of thermal resources from solar thermal power [146]. It remains to be seen whether the benefits of several power and commodity flows outweigh the drawbacks from increased system complexity and cost.

3.3. The impact of ocean thermal energy resources on power production profiles and plant design

In our earlier work [304], we already assessed the impact of ocean thermal energy resources on OTEC's power production and plant design, but only for four plants in Indonesia. In this sub section, we validate and further refine our earlier findings with global results.

In literature, OTEC is considered a steady and stable baseload generator [294,302,317]. Figure 50 examines this further and shows the impact of ocean thermal energy resources on net power production, exemplified for 136 MW_{gross} plants in four regions. We show that the shape of OTEC's power production profile is mainly determined by the surface seawater temperature, whereas its magnitude is mainly determined by the deep-sea water temperature. The former observation is apparent for Japan, where the net power production profile follows the seasonal changes of surface seawater temperature more closely than the other profiles do. The latter observation becomes clear when comparing the cases of India and Puerto Rico. Although the surface seawater temperature tends to be higher in India than in Puerto Rico, the net power production in India is lower. This is because the deep-sea water temperature in India is roughly 2 °C higher than the one in Puerto Rico. Given the consequent lower temperature range between evaporator and condenser as well as the increased deep-sea water pumping power, the plant in India needs more working fluid and deep-sea water to produce the same net power as the plant in Puerto Rico, which results in a lower net efficiency.

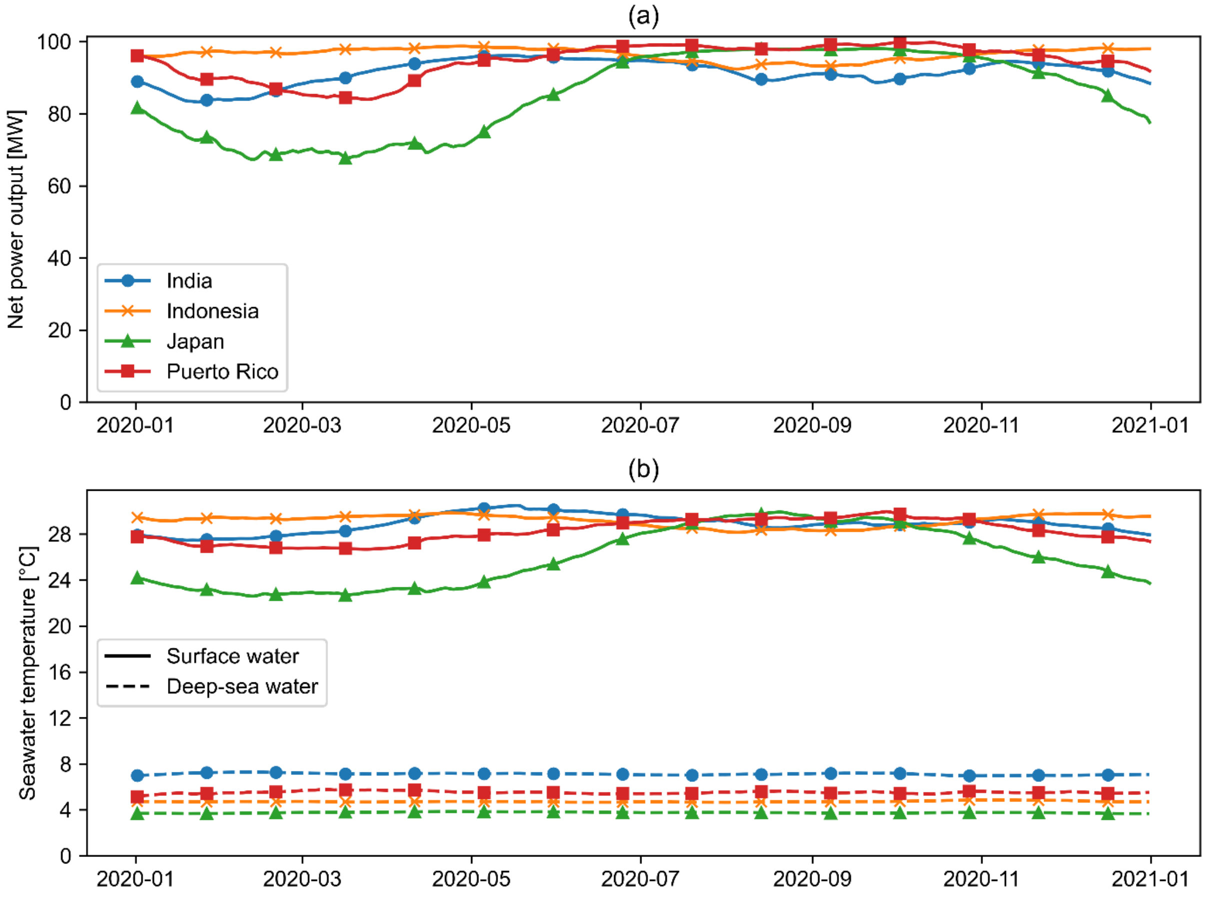


Figure 50. Time series data for four example countries showing (a) net power production and (b) warm surface seawater temperature (solid line) and cold deep-sea water temperature (dashed line). All plants in the shown countries are sized for a nominal gross power output of 136 MWgross.

Figure 51 maps the temperature configurations with the lowest LCOE across the world. The map only displays configurations with an occurrence of more than 1%. As shown in Figure 52, 79.6% of all analysed sites are designed with configuration 1 (minimum surface and maximum deep-sea water temperature), followed by configuration 2 (median surface and maximum deep-sea water temperature) with 14.2%.

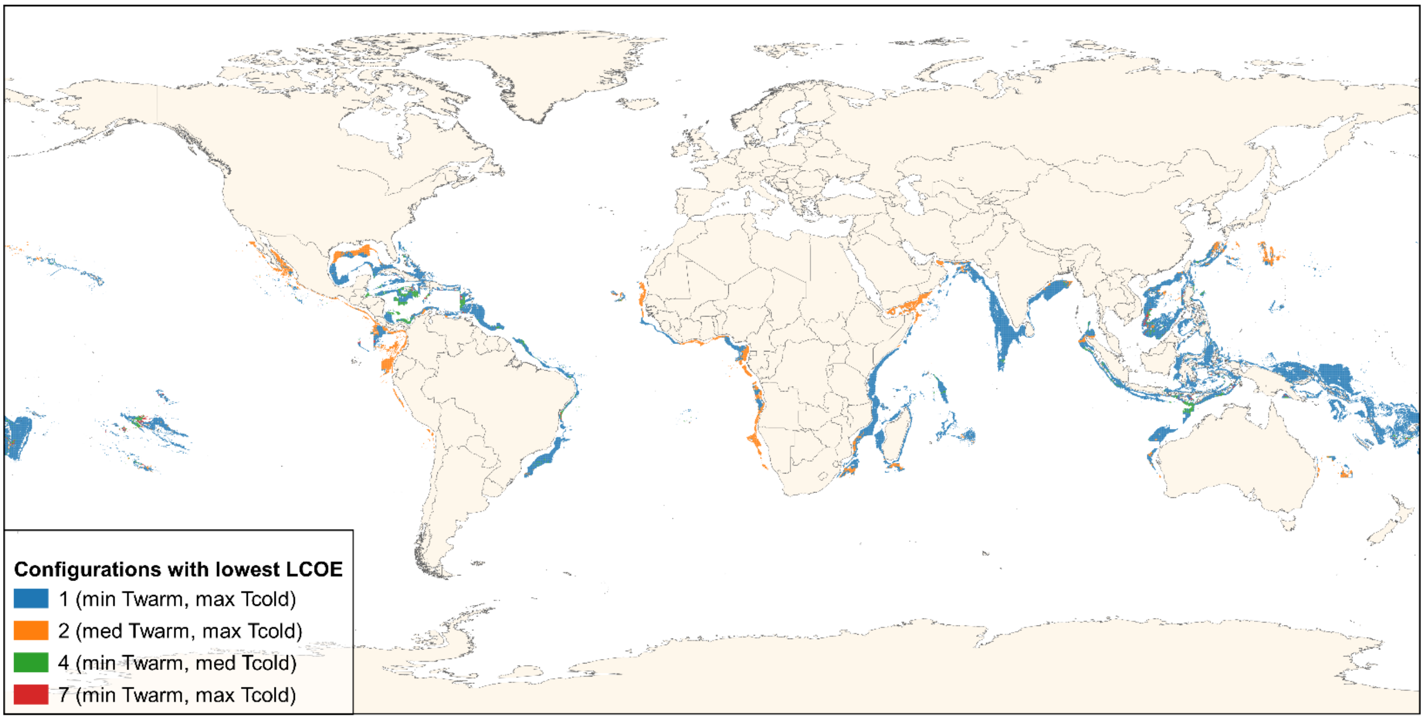


Figure 51. Configurations yielding the lowest off-design LCOE across the world under low-cost assumptions (N = 162,620 sites). Twarm in the legend refers to the warm surface seawater temperature; Tcold refers to the cold deep-sea water temperature.

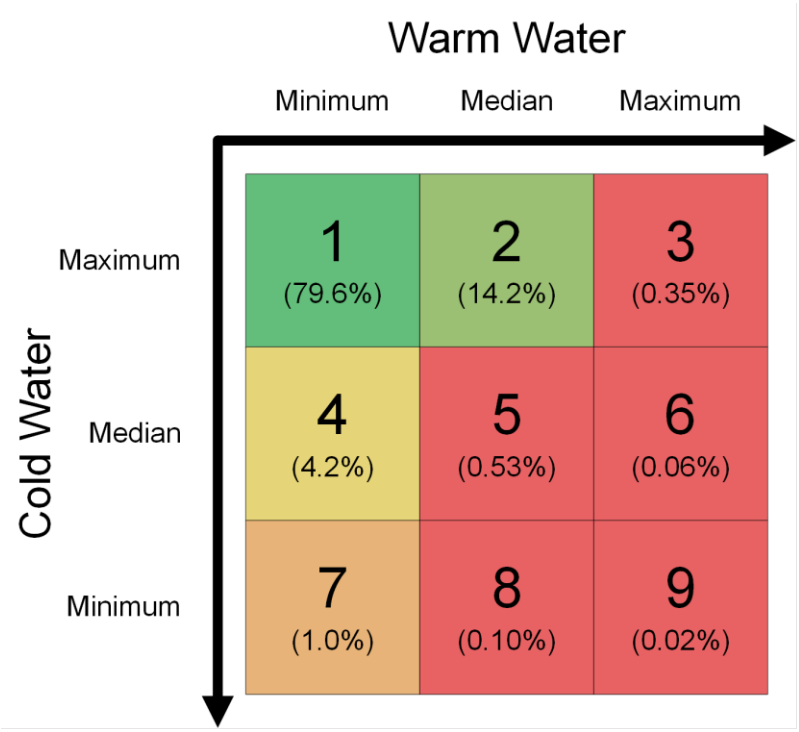


Figure 52. Design configurations and the percentage of them returning the lowest off-design LCOE (N = 162,620 sites). The cells above are coloured from red to green based on increasing percentage.

Based on Figure 53, we deduce several rules for sizing OTEC plants economically. The warm system side tends to be sized for minimum warm seawater temperature (i.e. configurations 1, 4, and 7) if the maximum warm seawater temperature is at least 25 °C with seasonal fluctuations of 10 °C or less. If the surface seawater is cooler and/or more fluctuating throughout the year, pyOTEC tends to size the warm system side for median warm seawater temperatures (mainly configuration 2) as a more conservative design either incurs too high costs or returns infeasible plant designs (i.e. pumping power > gross power output). From the cold system side, we observe that plants tend to be designed less conservative the lower the minimum cold seawater temperature and its fluctuations are.

These findings mostly harmonise with our earlier work [304] for Indonesia, where we concluded that conservative system designs show the best economic performance. Against our earlier results, we did find sites at which the less conservative configurations 3, 6, and 9 yielded the lowest LCOE. However, such cases are rare with a combined occurrence of 0.43% across the global sample. Therefore, we see our earlier findings validated and consolidated for global application, at least under the used technical and economic assumptions.

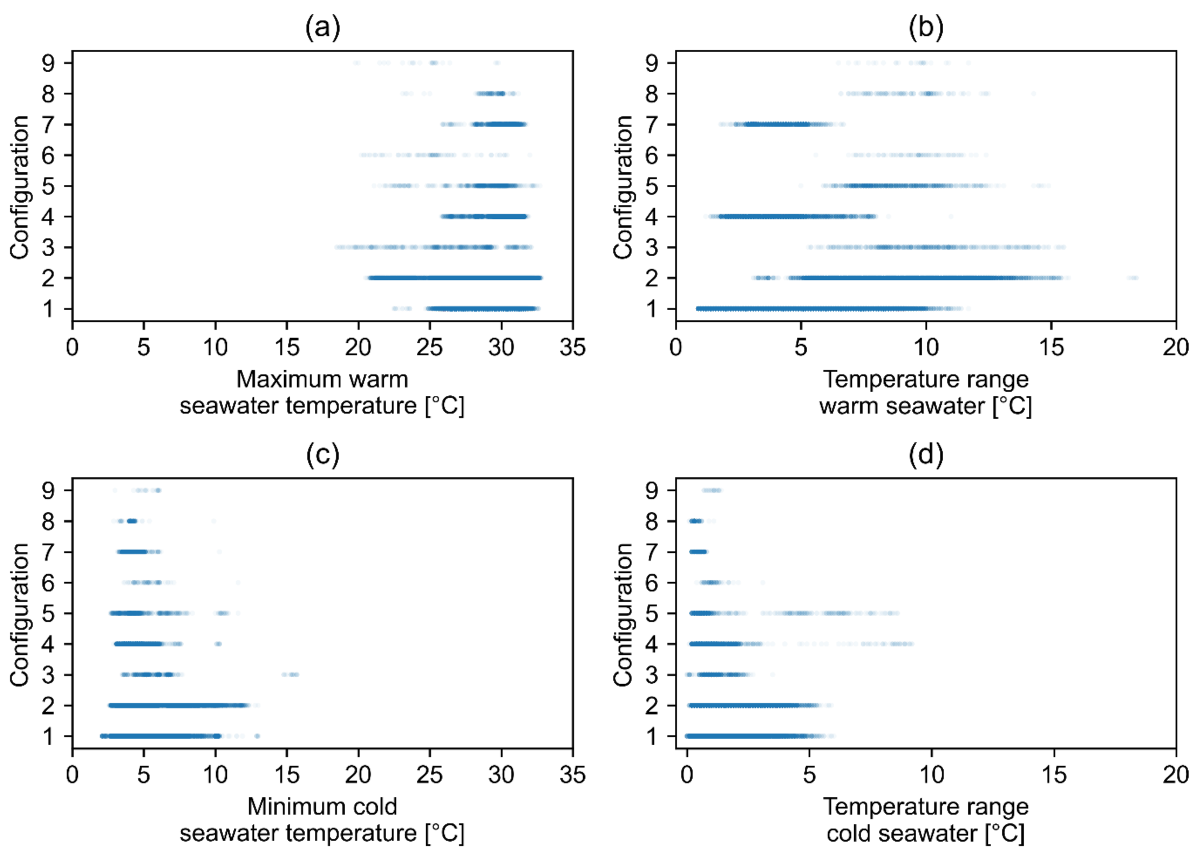


Figure 53. The configurations yielding the lowest off-design LCOE of all analysed OTEC plants (N = 162,620 sites) plotted against the minimum seawater temperature and temperature range. (a) and (b) refer to the warm surface seawater temperature, (c) and (d) refer to the cold deep-sea water temperature. The temperature range is the difference between maximum and minimum seawater temperature throughout the modelled time horizon and reflects the variability of ocean thermal energy resources at the studied sites.

3.4. Sensitivity Analysis

Figure 54 displays the results of the sensitivity analysis for the sites in Indonesia (N = 14,422 sites). The LCOE is most sensitive to changes in availability factor a_f and discount rate r, which underlines the importance of reliable operation and sound financing if the discount rate represents weighted average cost of capital, for example. Out of all cost components, structure and mooring costs are most impactful, which might motivate further research into onshore OTEC, which does not incur these costs. Moreover, the LCOE is moderately sensitive to technical parameters, like overall heat transfer coefficient U, pressure drop coefficient K_L, and hydraulic seawater pump efficiency $\eta_{pump,hyd}$.

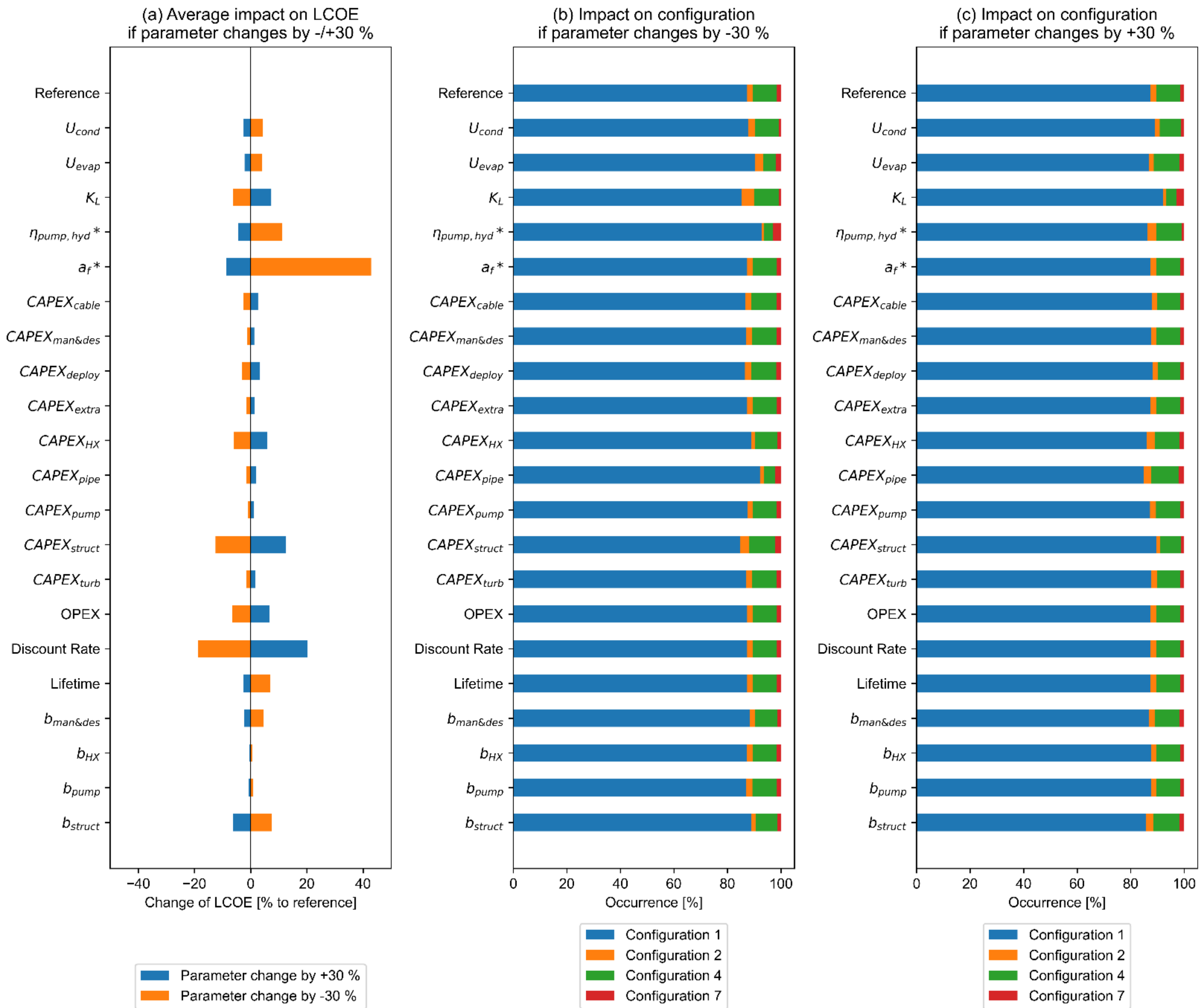


*Figure 54. The sensitivity of LCOE and configuration of 136 MWgross plants in Indonesia (N = 14,422 sites) to changes in technical and economic parameters by -/+30 %. Parameters marked with * could not be increased by +30 % beyond 100% and are instead capped at 100%. See abbreviations table for meaning of symbols and indices.*

Regarding the configuration, we observe that the overall composition persists across all studied parameters: The most conservative configuration 1 (minimum warm seawater temperature, maximum cold seawater temperature) is selected most often, followed by the less conservative configuration 4 (minimum warm seawater temperature, median cold seawater temperature). Configuration 1 becomes even more dominant the worse the underlying technical parameters are, most visibly for the hydraulic seawater pump efficiency $\eta_{pump,hyd}$ and pressure drop coefficient K_L (note the latter's inverse effect). Configuration 1 is dominant because oversizing OTEC plants contributes to a stable baseload generation to recover the plants' CAPEX; and worse technical system parameters seem to reinforce this effect. Out of all cost components, structure and mooring as well as pipe costs are most impactful, albeit in opposite directions. In our cost model, structure and mooring costs depend on the plant's gross power output and not on configuration. For these costs, configuration 1 becomes less dominant as fewer costs need to recovered, thus making baseload generation less important. Pipe costs, in contrast, depend on the dimensions and amount of pipes and vary per configuration. With lower pipe costs, oversizing the pipes becomes cheaper, thus making configuration 1 even more attractive. The scaling exponents *b* reflecting OTEC's economies of scale do not affect the composition of configurations significantly.

The observations above consolidate our earlier and present findings, namely that conservative plant designs tend to return the lowest LCOE.

4. Conclusion

This chapter presents the open-source model pyOTEC, which designs *Ocean Thermal Energy Conversion (OTEC)* plants for best economic performance across large regional scopes using spatiotemporally resolved ocean thermal energy resource data. Sites for OTEC deployment are based on a site selection analysis using exclusion criteria like water depth, marine protected areas, and exclusive economic zones. We apply pyOTEC to more than 100 countries and territories with technically feasible OTEC sites and design more than 150,000 plants to assess OTEC's global economic potential. This work contributes to the research field by (1) providing the first global assessment of economic OTEC resources, (2) showing the impact of availability and seasonality of ocean thermal energy resources on OTEC's technical and economic performance, (3) validating and consolidating global OTEC design guidelines, and (4) generating spatially and temporally explicit net power production profiles for energy system optimisation models.

Our results show that more than 107 PWh/year could be generated globally with OTEC, although this potential might be less if more advanced negative environmental and economic impacts were considered. LCOEs tend to be the lowest along the equator in South-East Asia and South America, and higher in Africa, East Asia, and Australia. If fully scaled to 136 MW_{gross}, OTEC can also be economically attractive in the latter regions with LCOEs below 20 US¢(2021)/kWh. Small-scale systems also show economic potential as seen for small island developing states. These islands are OTEC's most relevant niche as systems below 10 MW_{gross} could fully and cost-effectively substitute Diesel generators, which might be more challenging with other renewables due to limited land availability, amongst others. The global analysis shows that in most cases the best economic performance is achieved if systems are designed conservatively based on worst-case surface and deep-sea water temperatures. The warm system side tends to be designed conservatively if the maximum surface seawater temperature is above 25 °C and fluctuates by less than 10 °C throughout the year. The cold system side tends to be designed more conservatively with warmer and more fluctuating deep-sea water temperatures. The preferrence of conservatively designed OTEC plants has been tested and validated via a sensitivity analysis for Indonesia, which revealed the availability factor and discount rate as the most influental inputs for the LCOE. For the selected configuration, the hydraulic seawater pump efficiency and pipe costs are most impactful, although the overall composition of preferred configurations only changes slightly.

We conclude that OTEC is a technically and economically intriguing technology despite its relatively high current LCOE compared to the ones of other renewables. Right now, it seems like most countries put their hopes on solar photovoltaics, wind power and battery storage to master the energy transition. But just like in finance, we believe that diversification is an essential element of power systems. With this in mind, we hope that the world learns to appreciate OTEC's merits and starts promoting its commercialisation. After all, it would not only be the communities of small island states that could benefit from clean, stable, and affordable OTEC electricity, but also the ones of large continental coastal states.

7. Full decarbonisation scenarios for Indonesia’s power sector

Abstract: Indonesia has large renewable energy resources, but still relies mainly on fossil fuels to meet electricity demand. There is little research on what Indonesia’s options for power system decarbonisation are considering resource availability and variability, transmission networks, and uncertainty of inputs, like costs. This chapter explores full decarbonisation scenarios for Indonesia’s power sector under different network topologies, cost projections, power generation profiles, and demand growth rates, amongst others. Indonesia’s options for decarbonisation are manifold, but lowest-cost solutions are mostly based on photovoltaic (PV), pumped hydro storage, and inter-island power cables. In 2050, 50 GW of inter-island lines would enable 468 GW of PV providing half of total generation, coupled with 172 GW of pumped hydro, at levelised costs of 60 US$(2021)/MWh. Biomass, large hydro, and geothermal remain important baseloads with at least 77 GW and 36% of total generation. Key findings, like the importance of PV and island links from Kalimantan to Java, are corroborated with a sensitivity analysis, e.g., for costs and resource availability. Full decarbonisation by 2040 avoids 586 $MtCO_2e$ against the 2050 target, but poses more challenges for renewables upscaling and fossil capacity retirement. Future work could expand our model for other energy carriers, sectors, and technologies.

This chapter has been submitted for publication in a peer-reviewed scientific journal as Langer J, Lombardi F, Pfenninger S, Rahayu HP, Al Irsyad MI, Blok K. Full decarbonisation scenarios for Indonesia's power sector.

For this dissertation, we also added Box IV that discusses whether and to what extent the inclusion of other RET omitted in this research would have on the results presented here (e.g., rooftop PV, wave and tidal power, and concentrated solar power).

This chapter is based on the published preprint version from February 2024. Since then, the manuscript has been further developed based on the feedback from peer review and the following changes from our own initiative:

- Offshore floating PV was added as a technology
- The cost assumptions are now based on the 2024 Indonesia Technology Catalogue [330], which offers the most recent and location-specific cost data for Indonesia today
- The wind speed threshold for onshore and offshore wind was increased from 4 m/s to 6 m/s, which reduced the local technical potential, but significantly improved the power production profiles of the potential that remained

Despite these changes, the key findings remain, namely that Indonesia's fully decarbonised power system mainly foots on solar power, island links, dispatchable generators, and energy storage. The main differences between this chapter and the revised manuscript are:

- Power systems without island links mainly deploy offshore floating PV now instead of offshore wind and OTEC. The levelised generation and storage costs consequently become much lower, but still higher than the costs of the interconnected systems
- Battery storage becomes more cost-effective than pumped hydro from 2040 onwards and therefore sees more deployment than shown in this chapter
- Onshore wind sees noticeable local deployment and remains a cost-effective solution even under conservative cost assumptions

The revised manuscript is not shown here as it is still under review as of April 2024 and thus subject to change. For future reference, we recommend the use of the peer-reviewed journal article version once it is published.

1. Introduction

Indonesia is a fast growing country that currently relies on abundantly available domestic coal to meet the increasing local electricity demand (62% in 2020) [235]. The country pledged to become carbon-neutral by 2060 [9] and can draw from diverse and extensive renewable energy resources [220]. Renewables only supplied 18% of electricity in 2020 [235], so the transformation towards a carbon-neutral, or even fully decarbonised, power system would be substantial and requires careful energy planning.

Energy System Optimisation Models (ESOMs) are powerful tools to support energy planning decisions. They allow exploring different energy systems and their technical, economic, and environmental trade-offs. State-of-the-art ESOMs, like Calliope [23] and PyPSA [22], are able to capture the spatial and temporal fluctuations of variable renewables and consist of nodes and interconnections between them. Each node contains location-specific, temporally resolved profiles for electricity demand and power production, while interconnections represent the power transmission lines connecting these nodes.

There is already a rich body of ESOM-based peer-reviewed and grey literature for Indonesia. Peer-reviewed publications [25,26,36,37,41–43,60,61,331] mostly assume a national copperplate approach, meaning that all demand and supply occur in one single node without interconnections, thereby disregarding the complexity of Indonesia's current grid topology of several, disconnected systems. As of now, only two pairs of islands are connected in Indonesia, namely Java and Bali and Bangka and Sumatera [9]. Moreover, previous studies use time- and location-invariant assumptions for renewable power supply and demand. In contrast, recent grey literature considers hourly demand and supply as well as inter- and intra-island transmission networks, however either only for sub-national cases [27,30,38,39] or at limited spatial resolution [29]. Almost all studies tend to rely on one set of parametric assumptions and do not address the sensitivity of their results to changes in the assumed parameters. A report by IESR [27] is an exception, where the discount rate, capital expenses and renewable energy share are varied in alternative scenarios.

This disregard for uncertainty is especially critical considering the recent cost reductions of renewables, shown in Figure 55. Studies that use historic high costs for renewables, without accounting for expected future cost reductions portray fossil-fuel-based solutions as more cost-effective for emission reductions, such as switching from coal to natural gas [8–10] or the deployment of carbon capture and storage [37,60,61]. In contrast, studies [26,28–31,38,39] that consider more recent cost data and further future cost reductions suggest that high shares of *photovoltaics (PV)* [28,29], wind power [30], hydropower [38], and geothermal [39] are techno-economically attractive. To our knowledge, no study has simultaneously captured Indonesia's electricity grid topology, spatiotemporal variability of renewable power supply and demand, and uncertainty of technical and economic input data. This prevents the provision of technically-sound and uncertainty-aware insights that may support the urgent planning of the Indonesian energy transition. Furthermore, only two studies [28,41] addressed full decarbonisation scenarios for the Indonesian power system.

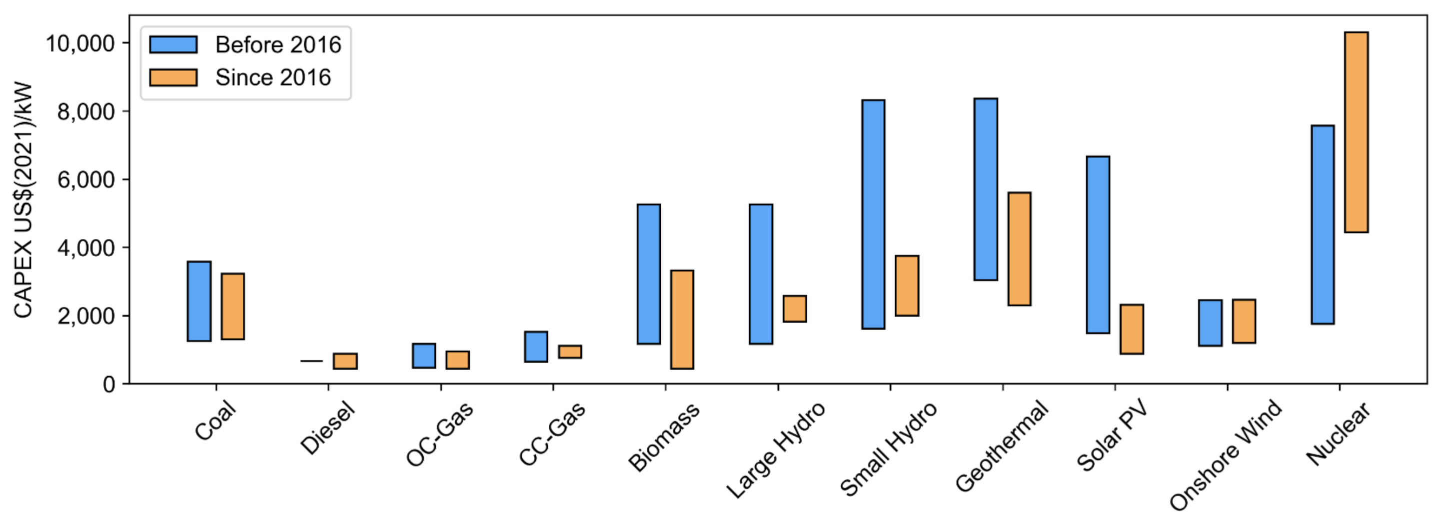


Figure 55. Ranges of Capital Expenses (CAPEX) from sources used in contemporary Indonesian energy system modelling literature. If the year value of the currency cannot be found, we use the year of publication. For references since 2016, see Appendix Q. Coal: pulverised supercritical coal plant; diesel: reciprocating engine; OC-Gas: open-cycle gas turbine; CC-Gas: combined-cycle gas turbine; Biomass: direct combustion steam turbine fed with rice or palm oil husk; large hydro: reservoir plant above 30 MW; small hydro: run-of-river plant below 30 MW; geothermal: flash steam plant; solar PV: fixed-tilt solar photovoltaics; onshore wind: horizontal axis 3-blade turbine; nuclear: heavy water reactor.

This chapter aims to fill this gap by providing a broad range of possible least-cost options for the full decarbonisation of Indonesia's power system. We use spatially and temporally explicit demand and renewable resource data as well as costs and cost projections sourced from literature. We model fully decarbonised electricity systems and study the impact of inter-island power transmission, decarbonisation rate, costs, electricity demand growth, shape of demand and power production profiles, and available renewable energy resources. We explore the trade-offs between the resulting system designs in terms of installed generation and storage capacity, generation mix, and generation and storage costs. The 2050 designs are benchmarked against the current 2020 system. Beyond Indonesia, this chapter is globally relevant as our findings could be scaled to other island and archipelagic states as well as other fast-growing, fossil-fuel dependent economies.

2. Methods and materials

We use the open-source ESOM Calliope [23] to model the full decarbonisation of Indonesia's electricity system. Calliope has already been used to model a variety of energy systems across geographical contexts (e.g., in Africa [332] and India [333]) and scales (e.g. for cities [334], countries [335], and entire continents like Europe [336]), demonstrating high versatility while ensuring high spatial and temporal resolution and customisable technical detail. Calliope uses nodes and interconnections to establish model regions and their production, consumption, storage, and exchange of energy carriers. In this study, we only focus on electricity and omit other energy carriers like heat and hydrogen, which keeps the model's complexity and runtime computationally feasible but omits sector-coupled solutions for the entire energy system. Each of Indonesia's 34 provinces is represented by one node. For the grid, we consider two network topologies, one with and one without island links. All used time series data is resampled to 4-hour time steps to compromise between computational tractability and the need to capture intra-daily fluctuations of renewable generation and demand (see Appendix O for impact of temporal downsampling). We assume a location- and technology-independent discount rate of 10% as commonly used for Indonesia [30,41,66,178]. Calliope determines the necessary generation, storage, and transmission capacities to meet demand within the user-defined boundaries. The optimisation process in Calliope aims to minimise the overall system cost.

First, we apply Calliope for the reference scenarios, which assess the full decarbonisation of Indonesia's power sector by 2040 and 2050 for both network topologies. We assemble the decarbonisation pathways by modelling the years 2030, 2040, and 2050 individually from scratch with their respective sets of techno-economic inputs. This means that the planning of capacity expansion in each modelled decade is "myopic" with respect to changes in boundary conditions in the future and past, e.g., historic and projected future costs. Then, we conduct a scenario and sensitivity analysis, for which we change one or several of the reference parameters to assess their impact on the outputs. We compare all decarbonisation pathways and 2050 configurations with each other and with the existing 2020 configuration. This comparison is based on various factors, including installed generation and storage capacity, electricity generation, as well as levelised generation and storage cost.

In the following sub-sections, we elaborate on the methods and materials for demand, generation, storage, and transmission.

2.1. Demand

Time series data on Indonesian electricity demand is currently not openly available. We were able to obtain 2019 demand data for Kalimantan used in an earlier study [337] via a formal request to Indonesia's state utility company PLN. For the sake of transparency and replicability, we use publicly available Malaysian 2020 national demand data [338] scaled to the annual demand of each Indonesian province, which is available via public records [339]. Malaysia and Indonesia are similar in terms of local climate, but less so in other terms, such as economic activity, with Malaysia having a higher national GDP per capita of 12,000 US$(2022) compared to Indonesia's 4,800 US$(2022) [340]. Hence, the Malaysian time series data might reflect the demand profiles of Indonesian provinces more or less well based on the local conditions. We assess the impact of the demand profile shape by running an alternative scenario that uses the abovementioned Kalimantan profile (see Figure 56). Below, we describe the steps with which the Malaysian and Kalimantan data is further processed.

First, we convert the time zone from Malaysian/ West Indonesian time to Coordinated Universal Time. Then, we resample the data to hourly steps and fill empty time steps via linear interpolation (necessary for 1.2% of the Malaysian data). Next, we scale the data to the demand of Indonesia's provinces [339] with a time-invariant scaling factor. For example, if an Indonesian province has a 50% lower total annual electricity demand than Malaysia, all values are reduced by 50%. We also incorporate nationwide distribution losses of 7.2% [339] to all demand profiles to reflect how much electricity must be generated to meet end-user demand. For the demand in 2030, 2040, and 2050, we multiply the scaled demand profiles by a constant growth rate taken from PLN's 2021–2030 business plan [9], assuming that the growth rates remain applicable until 2050. The growth rates vary from 4.0% p.a. in Java-Bali-Madura to 8.3% p.a. in Maluku, Nusa Tenggara, and Papua. The national weighted average growth rate is 4.8% p.a., using regional 2021 electricity demands as weights. To study the impact of demand growth, we assess alternative scenarios with a nationwide growth rate of 8.3 % p.a.

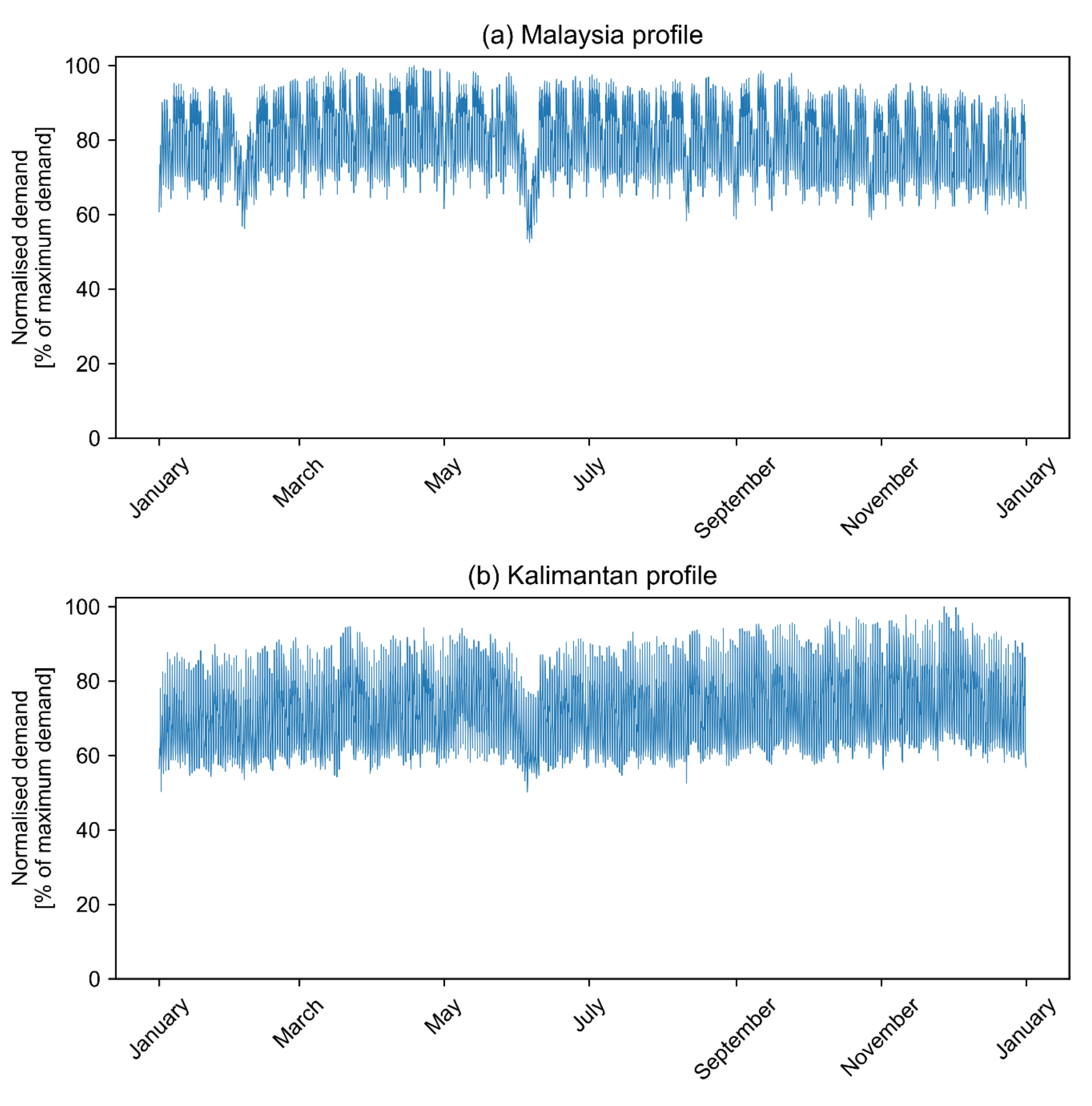


Figure 56. Normalised, hourly demand profiles used in this study.

2.2. Generation and storage

All the electricity generation and storage technologies studied, along with their underlying technical and economic assumptions, are shown in Table 28. To outline the decarbonisation pathways, we start with Indonesia's power system in 2020 [235,288]. We assume that existing fossil capacity is retired linearly without future additions. For full decarbonisation by 2040, for example, we assume that fossil capacity in 2030 is half of 2020 fossil capacity, and zero in 2040. The 2020 system generation costs are taken from PLN's statistics report [339].

In our model, the maximum installable capacity of most technologies is restricted by their technical potential per region. We use official data for potentials of geothermal [341], large hydro and biomass [5], and data from existing peer-reviewed works for small hydro [49], utility-scale land-based PV [13], onshore wind [45], offshore wind [232], and *Ocean Thermal Energy Conversion (OTEC)* [18]. For nuclear [342,343], we draw from recent official plans for West Kalimantan and Bangka island. Table 29 lists the constraints imposed on each technology, while Table 30 lists the resulting maximum installable capacity per technology and region.

For storage, we consider battery and closed-loop pumped hydroelectric energy storage (pumped hydro for the remainder of the chapter), as well as the reservoirs of large hydro. While battery storage is not constrained by location and storage capacity, we limit pumped hydro's maximum installable capacity to areas outside of nature conservation zones using the global pumped hydro dataset by Stocks et al. [344]. For battery storage and pumped hydro, respectively, we assume a round-trip efficiency of 92.0% and 75.7% [280], storage losses of 0.96% per day [280] and 0% [335], and a lifetime of 30 and 50 years [280]. For the large hydro reservoirs, we assume the same storage efficiencies as for pumped hydro.

Table 28. Technical and economic assumptions for power generation and storage technologies considered in this study. “X” refers to time series profiles for which efficiency has already been accounted for. Efficiencies, lifetimes, and minimum loads refer to 2050 estimations from [280]*, except for nuclear power (efficiency and lifetime from* [336]*, minimum load from* [345]*). All costs refer to median values in US$(2021). See Appendix Q and R for sources of cost and cost projection assumptions.*

Technology [unit]	**Coal**	**Diesel**	**CCGT**	**OCGT**	**Large hydro**	**Biomass**	**Geo-thermal**	**Small hydro**	**PV**	**On-shore wind**	**Off-shore wind**	**Nuclear**	**OTEC**	**Battery**	**Pumped hydro**
Efficiency [%]	40	48	61	40	80	32	17	80	X	X	X	40	X	-	-
Lifetime [year]	30	25	25	25	50	25	30	50	40	30	30	50	30	30	50
Minimum load [%]	20	6	15	15	0	30	30	0	0	0	0	50	0	-	-
Median CAPEX $[\text{US\$/kW}_{gen}]/[\text{US\$/MWh}_{stor}]$															
2021	1,559	792	895	798	2,262	2,154	3,954	2,686	1,194	1,660	4,325	6,716	6,668	300,200	22,082
2030	1,535	792	876	777	2,262	1,923	3,556	2,686	825	1,497	3,779	6,330	6,048	162,186	22,082
2040	1,532	787	860	764	2,262	1,721	3,123	2,686	698	1,412	3,524	6,059	5,511	125,147	22,082
2050	1,512	782	844	751	2,262	1,520	2,872	2,686	571	1,326	3,269	5,789	4,974	88,108	22,082
Median fixed OPEX $[\text{US\$/kW}_{gen}\text{/year}]/[\text{US\$/MWh}_{stor}\text{/year}]$															
2021	45	9	23	22	46	83	45	59	17	49	20	138	200	9,456	221
2030	45	9	23	22	45	76	42	57	13	43	17	118	181	4,735	221
2040	45	9	23	22	44	71	40	56	11	39	15	104	165	3,548	221
2050	45	9	23	22	43	66	38	55	9	35	13	91	149	2,360	221
Median variable OPEX [US$/MWh/year]															
2021	2.5	7.1	3.0	4.3	0.7	5.2	0.7	0.6	0	0	25	1.7	0	0.13	1.44
2030	2.5	6.6	3.0	4.3	0.7	5.2	0.7	0.5	0	0	21.8	1.7	0	0.13	1.44
2040	2.5	6.5	3.0	4.3	0.7	5.2	0.7	0.5	0	0	19.8	1.7	0	0.13	1.44
2050	2.5	6.4	3.0	4.3	0.7	5.2	0.7	0.5	0	0	17.7	1.7	0	0.13	1.44
Fuel costs $[\text{US\$/MWh}_{thermal}]$	12.1	38.7	23.3	23.3	0	9	0	0	0	0	0	2.9	0	0	0

Table 29. Constraints and further remarks relevant to the maximum installable capacity of renewables and nuclear energy in this study. For further details, see the respective references.

Technology	Ref	Constraint	Remarks
Biomass	[5]	–	Sourced from agricultural waste (mainly from palm oil, rice, and rubber production) as well as municipal waste
Geothermal	[341]	–	Maximum installable capacity equals sum of possible, proven, and expected reserves as well as currently installed capacity
Small hydro	[49]	• Distance to coastline ≥ 15 km (see Appendix P) • Outside of protected and natural-catastrophe prone areas	Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (2001–2020)
Large hydro	[5]	–	• Ratio between energy and storage capacity: 0.15 (i.e., reservoir can deliver rated power for 6.67 hours) [344] • Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (2001–2020)
PV	[13]	• Outside of water bodies, built-up infrastructure, agricultural land, forests, as well as protected and natural-catastrophe prone areas • Slope < 15°	• Capacity density: 60 MW_p/km^2 • Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (2001–2020)
Onshore wind	[45]	• Outside of water bodies, built-up infrastructure, as well as protected and natural-catastrophe prone areas • Slope < 30° • Altitude < 2,000 m • Average 100m wind speed ≥ 4 m/s	• Rated turbine power and rotor diameter: 2.5 MW and 116 m (median of turbine set studied in source) • Spacing of turbines: 5D × 10D (D being the rotor diameter) • Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (2001–2020)
Offshore wind	[232]	• Outside of shipping and subsea cable routes, as well as protected and natural-catastrophe prone areas • Inside exclusive economic zone • Visual impact buffer of 10 km around coastlines • Water depth < 55 m • Average 100m wind speed ≥ 4 m/s	• Low-wind-speed offshore turbine • Rated turbine power and rotor diameter: 2.1 MW and 114 m (median of turbine set studied in source) • Spacing of turbines: 10D × 10D (D being the rotor diameter) • Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (2001–2020)
Nuclear	[342,343]	• Only West Kalimantan and Bangka Belitung Island • Total installed capacity capped at 35 GW	35 GW based on official press release
OTEC	[18]	• Outside of protected and natural-catastrophe prone areas • Inside exclusive economic zone • Water depth > 1,000 m and ≤ 3,000 m	• Plant size: 136 MW_{gross} • OTEC plants models using pyOTEC model [346] • Mean and minimum power production profiles generated from 3 years of daily Global Ocean Physics reanalysis (2018–2020)
Battery	[335]	–	Ratio between energy and storage capacity: 0.25 (i.e., reservoir can deliver rated power for 4 hours)
Pumped hydro	[344]	Outside of protected and natural-catastrophe prone areas	Ratio between energy and storage capacity: 0.15 (i.e., battery can deliver rated power for 6.67 hours)

Table 30. Maximum installable generation and storage capacity per technology and region. "var" under column "Nuclear" stands for "variable" and means that there is no hard limit on installed nuclear capacity in Sumatera and Kalimantan, as long as total installed nuclear capacity does not exceed 35 GW. Battery storage is not listed here as we did not impose a maximum installable capacity threshold for it. The maximum installable capacity accounts for the capacities already installed today.

Region	Maximum installable capacity [GW]									
	Biomass	Geo-thermal	Small hydro	Large hydro	PV	Onshore wind	Offshore wind	Nuclear	OTEC	Pumped hydro
Java & Bali	7.4	4.4	2.9	4.4	50.0	63.7	95.7	0	26.9	513
Sumatera	15.2	5.3	12.1	15.6	1,953	35.3	194	var	40.1	832
Kalimantan	5.0	0.01	32.5	21.6	3,999	23.9	150	var	8.7	1,796
Sulawesi	1.8	1.2	5.7	10.3	1,005	45.4	11.9	0	54.0	2,193
Nusa Tenggara, Papua, and Maluku	0.7	1.3	17.4	23.2	1,961	88.8	306	0	109	2,582
Indonesia (total)	30.1	12.2	70.7	75.1	8,969	257	757	35	239	7,915

Regarding the power production profiles, we distinguish between variable and non-variable generators. For non-variable generators like coal, nuclear, and geothermal, Calliope dispatches these plants in the most cost-effective way to meet demand. For variable generators like PV and wind power, we prepared hourly capacity factors as shown in Figure 57 and described below. Studies like [13,45,232,346] used exclusion criteria, like nature conservation zones, to map technically feasible sites per technology across Indonesia and calculated site-specific power production profiles with a method called bias correction (see section 6.1 in chapter 1 for explanation). Using bias correction, we prepared the hydropower profiles for this study using the datasets by Hoes et al. [49] and the methods by Liu et al. [347], see Appendix P. The outputs of the site selection and bias correction are hundreds of technically feasible sites with 20 years (2001–2020) of hourly power production profiles across Indonesia and its provinces. For Calliope, we resample the power production profiles spatially by aggregating the profiles of all sites inside a province based on averages weighted by the occupied area (for PV and wind power) or installed capacity (for hydropower and OTEC). For the modelling with Calliope, we do not use the entire 20-year dataset, but only a single year. By default, we use the profiles from 2018 as its annual PV power production comes closest to the average annual PV production of the 20-year dataset. For the scenario analysis, we also run one case where we use the profiles from 2010, where the annual PV production was the lowest within the 20-year period (5% below average). The choice of years is based on PV because its technical potential is by far the largest in most parts of Indonesia, see Table 30. To ensure the computational feasibility of the study, the hourly profiles are downsampled to a 4-hourly resolution, which has a limited impact on the studied key metrics as shown in Appendix O.

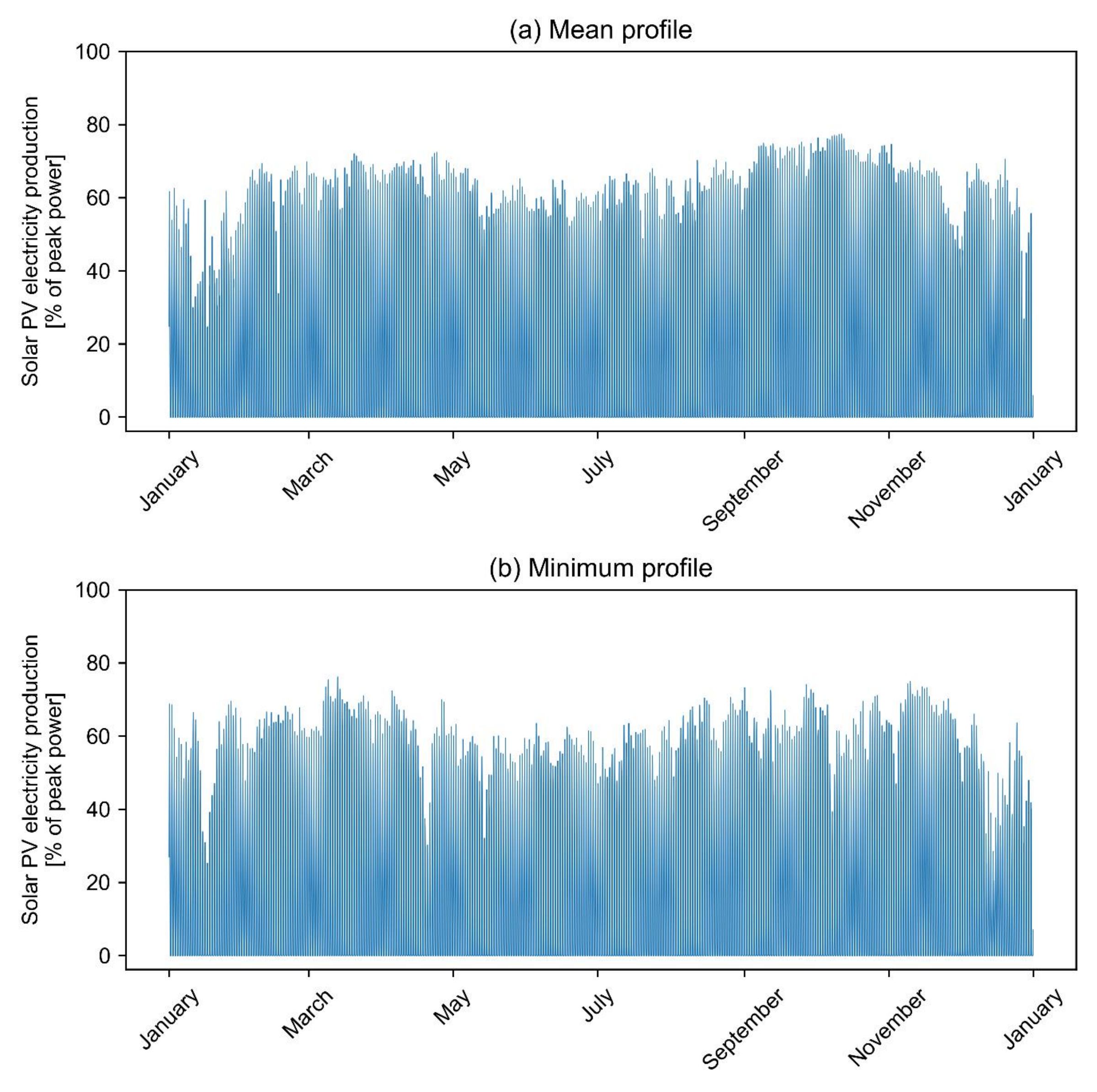


Figure 57. Example of hourly renewable power production profile showing the average PV production in East Nusa Tenggara, Indonesia.

Regarding the cost inputs, we use values from literature since 2016 for *Capital Expenses (CAPEX)* as well as fixed and variable *Operational Expenses (OPEX)*, see Appendix Q. After collecting all costs and converting them to US$(2021) (see Appendix B), we determine the minimum, median, and maximum cost values per technology as well as their minimum, median, and maximum cost reduction rates until 2050, see Figure 58. With these cost reduction rates, we calculate the respective 2030, 2040, and 2050 costs. See Appendix R for the projections sourced from literature.

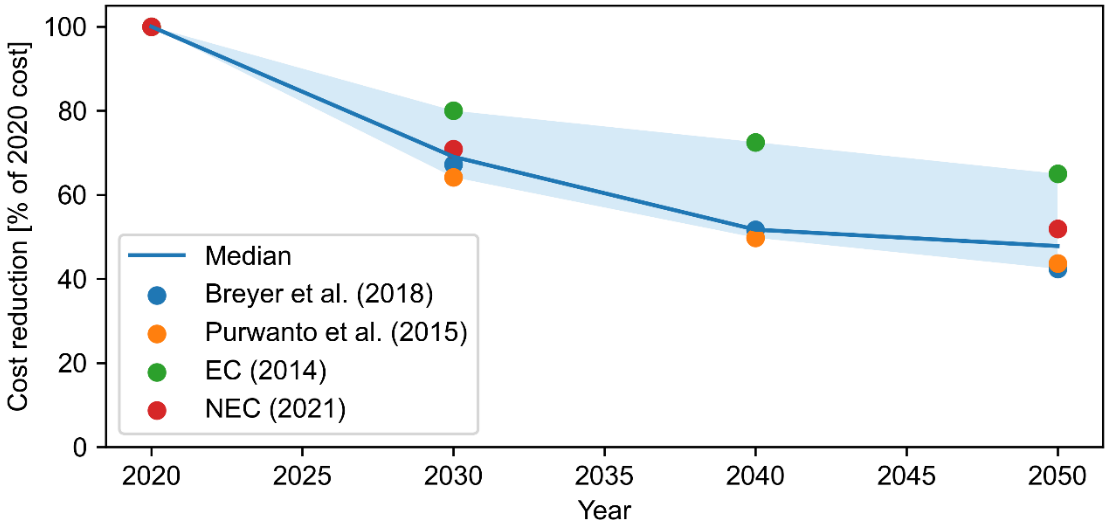


Figure 58. Cost projections found in literature [28,60,280,348]*, here shown for PV's CAPEX as an example. For 2050, we determine the minimum, median, and maximum cost reduction rates (shaded blue area), and apply them to the current cost estimations to obtain different levels of potential 2050 costs.*

We use the median cost data for the reference and alternative scenarios, and the minimum and maximum costs for the sensitivity analysis (see section 2.4). For offshore wind, we use the cost assumptions from Ref [232] and apply the cost reduction rates from literature. For OTEC, costs and their development are highly uncertain due to its early development stage. Based on earlier work on OTEC's upscaling towards commercial scale [19], we estimate its future cost with three cases. The first case assumes that OTEC will not be upscaled globally and that present costs also apply in 2050. The second case assumes that OTEC will be upscaled globally to an aggregated installed capacity of 10 GW by 2050 at a cost reduction rate, or *learning rate*, of 7% per doubling of installed capacity [19], and 2021 costs are adjusted for these learning effects to estimate 2030, 2040, and 2050 costs (see Appendix S for the upscaling scenario). The third case takes the median 2030, 2040, and 2050 costs from the two previous cases, which we use as default costs for most scenarios.

Due to the lack of consistent fuel cost data applicable to Indonesia, we use the same fuel costs for coal, diesel, natural gas [339], uranium (nuclear power) [349], and biomass [280] for all modelled years and scenarios.

2.3. Power transmission

The studied network topologies are shown in Figure 59. They are simplifications based on the current network and its potential development. The network without island links is based on PLN's 2021–2030 business plan [9]. The interconnected system is a concept [350] from the G20 meeting in 2022 hosted by Indonesia. We assume *alternating current (AC)* lines for land-based power lines and sub-sea *high-voltage direct current (HVDC)* lines for island links. We only consider the lines' active power flows, thus omitting aspects like voltage, frequency, and apparent power. Since national data on maximum active line capacity is not available, we let Calliope optimise the transmission capacities to up to 50 GW per link and test this decision during the sensitivity analysis.

For HVDC and AC lines, we use an efficiency of 95.6% per 1,000 km (beeline) [351] and 98% [339]. The HVDC lines' efficiency is distance-dependent as we know the distance between islands. Meanwhile, we do not know the total length of AC connections between nodes so we use the efficiency of the total transmission system [339]. That is also why we calculate transmission CAPEX per unit of installed active capacity rather than per unit of length. This approach has limitations due to the distance-dependent and fixed cost components of transmission lines in practice. Moreover, we use international cost data as up-to-date local cost data is not publicly available. We assume HVDC and AC CAPEX of 870 and 522 US$(2021)/kW, along with variable OPEX of 2.5 and 1.3 US$(2021)/MWh [335] for all scenarios, respectively.

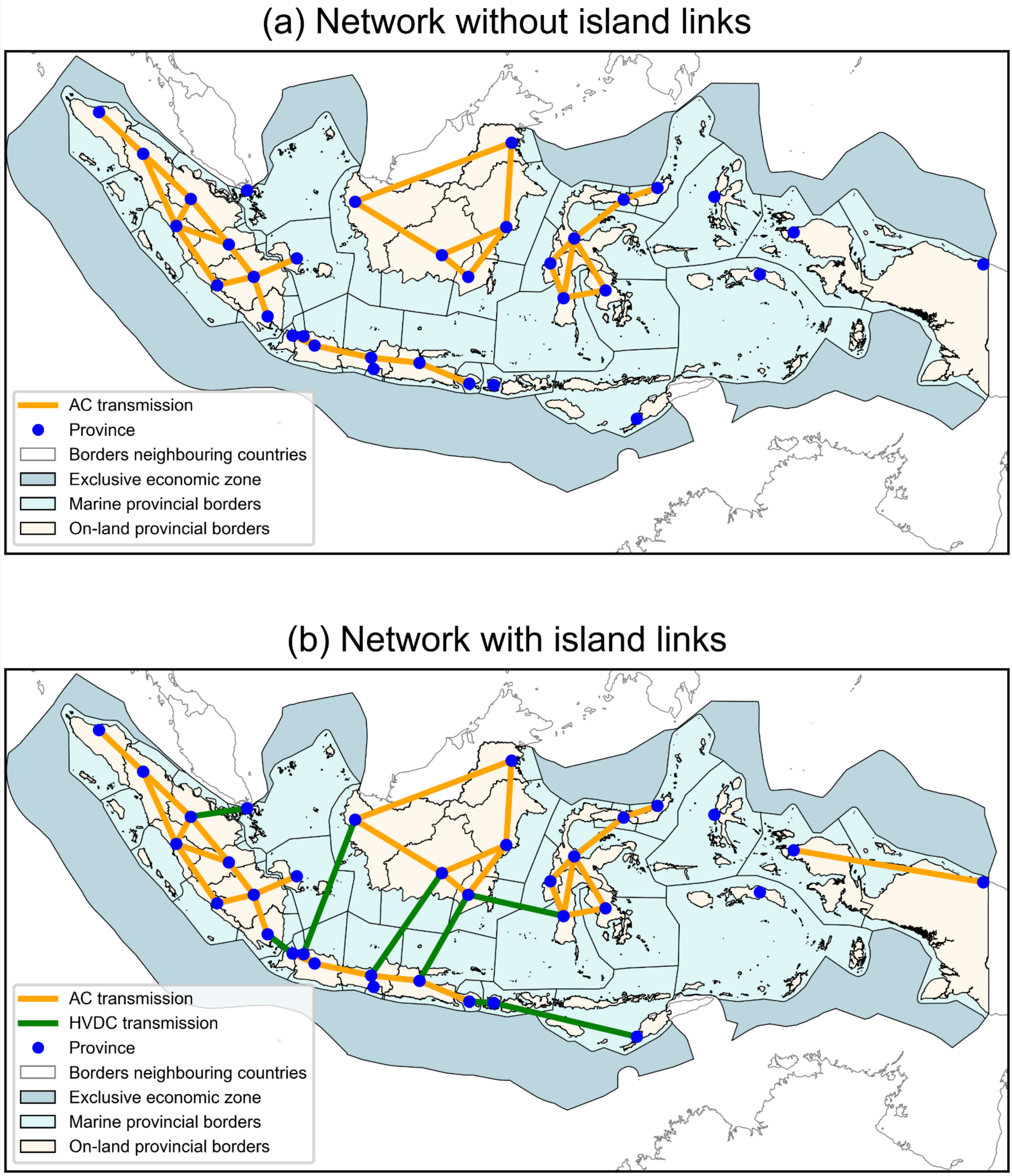


Figure 59. Transmission network representations studied in this chapter, based on (a) PLN’s 10-year business plan (RUPTL) until 2030 without island links (besides Java-Bali), and (b) a concept for Indonesia’s “super grid” (Pemodelan Tim NZE KESDM, presented at the Institute of Technology, Bandung, Indonesia, 18th Oct 2022)

2.4. Scenario and sensitivity analysis

The assumptions and setups described so far are default values used for the reference scenarios with and without island links. Besides the reference cases, we also perform a scenario and sensitivity analysis. With these analyses, several (scenario analysis) or single inputs (sensitivity analysis) are replaced with alternative values, while all other inputs remain unchanged. Table 31 shows the studied scenarios, and Table 32 shows the inputs being investigated for the sensitivity analysis. The reference and alternative scenarios are compared with each other and to the 2020 system in terms of installed generation and storage capacity, electricity generation [235], and levelised generation and storage cost [339].

The sensitivity and scenario analysis serve the purpose of (1) addressing the implications of inputs that are either uncertain (e.g., future cost) or not publicly available (e.g., transmission line data), (2) sharpening our key findings and the conditions under which they apply, and (3) estimating the significance of some of our works' limitations. For example, we increase the maximum installable PV capacity to estimate the impact of rooftop PV, which we omitted in this study due to lack of mapped rooftop PV potentials in Indonesia. Estimations exist [352], but these are not based on rooftop area, but residential floor space per household. This assumes that all buildings only have one floor (i.e., ground floor), and could therefore lead to significant deviations if buildings have several floors.

Table 31. Scenarios studied in this chapter and their properties.

Scenario	Network(s)	Time horizon	Properties/ changes from reference scenario
Reference	Both	2030–2050	Demand growth: regionally varying from RUPTL (i.e., 4.8% p.a. on average) Demand profiles: Malaysia Power profiles: 2018 (year with power production closest to the 20-year average) Costs: 2030, 2040, 2050 based on projections
Extreme demand growth	Both	2030–2050	Demand growth: 8.3% p.a. nationwide
Alternative demand profiles	Island links	2050	Kalimantan profile
Alternative power profiles	Island links	2050	Power profiles from the year 2010 (year with lowest PV production in 20-year dataset)
Weak cost reduction	Island links	2050	Maximum 2021 costs coupled with lowest cost reduction rates to calculate 2050 costs
Strong cost reduction	Island links	2050	Minimum 2021 costs coupled with highest cost reduction rates to calculate 2050 costs

Table 32. Parameters that are studied for the sensitivity analysis.

Parameter	Range of analysed variations
Renewable generation cost	Maximum 2021 cost – minimum 2050 cost
HVDC transmission line costs	870–2,000 US$(2021)/MW 2.5–6 US$(2021)/MWh
Maximum installable generation capacity (PV, geothermal, biomass, and large hydro)	+0–100% of default capacities (see Table 30)
Maximum HVDC transmission capacity	5–50 GW

3. Results and discussion

3.1. Island links enable cost-effective phase-out of fossil capacity

Figure 60 shows the results of the reference scenarios until 2040 and 2050 with and without island links. Panels (a) and (b) display the installed generation capacity. In 2030, island links are limitedly deployed because it is more cost-effective to meet demand locally with the remaining fossil capacity. After 2030, the impact of island links becomes significant as fossil capacity is further retired, which harmonises with previous work [29]. The system with island links mainly uses PV to supply electricity to high-demand regions like Java, e.g., from Kalimantan. Without island links, less PV and more wind power and OTEC are deployed as available land on Java for solar parks is limited.

Panels (c) and (d) show the installed storage capacity. For both networks, storage is only cost-effective after 2030 as dispatchable fossil capacity still meets demand. The reference scenario without island links entails roughly 1,900 GW of battery storage on Java to compensate for the lack of local renewable energy and pumped hydro resources. With island links, the model deploys 172 GW from the vast and more cost-effective pumped hydro resources on Kalimantan and Sumatera.

Panels (e) and (f) show the generated electricity to meet electricity demand. Fossil-fuelled generators still dominate the generation mix in 2030, despite their capacity being reduced by 33–50% and national demand growing by 4.8% p.a. This reflects the current fossil overcapacity in Indonesia's electricity system. In recent years, Indonesia overestimated future demand growth and consequently installed large amounts of coal power capacity. This has led to the risk of these assets being underutilised, potentially becoming stranded assets [31,353]. The current fossil overcapacity poses a significant barrier for Indonesia's energy transition, as the addition of renewable energy capacity would exacerbate the problem. Once fossil-fuelled generators are fully phased out, the 2050 systems with island links would utilise 468 GW of PV generating 53% of total generation, which is comparable to Breyer et al.'s [28] work and Reyseliani & Purwanto's [41] no-nuclear scenario. Without island links, however, Java's limited land availability restricts PV to just 18% of total generation, which is a novel finding.

Panels (g) and (h) show the levelised generation and storage costs. Up until 2030, costs decline regardless of studied transmission network due to the reduction of fossil overcapacity and the increased cost-effectiveness of the remaining plants. Without island links, costs rise after 2030 and more sharply after 2040 as early-stage, capital-intensive technologies like OTEC and large amounts of storage are necessary to meet Java's electricity demand locally. With island links, the cheapest technologies (i.e., PV) across the country are used to meet demand, resulting in consistent generation and storage costs of 60 US$(2021)/MWh. However, these costs might be higher in practice as Calliope plans the entire system from scratch for each year using that year's costs. For example, the system modelled for 2050 only uses the 2050 cost assumptions, and does not consider capacity that was modelled for 2040 with 2040 cost assumptions. Consequently, the costs of the modelled year do not reflect the costs of technologies that were present before. Accounting for these earlier costs, the differences between the 2040 and 2050 pathways would become more pronounced.

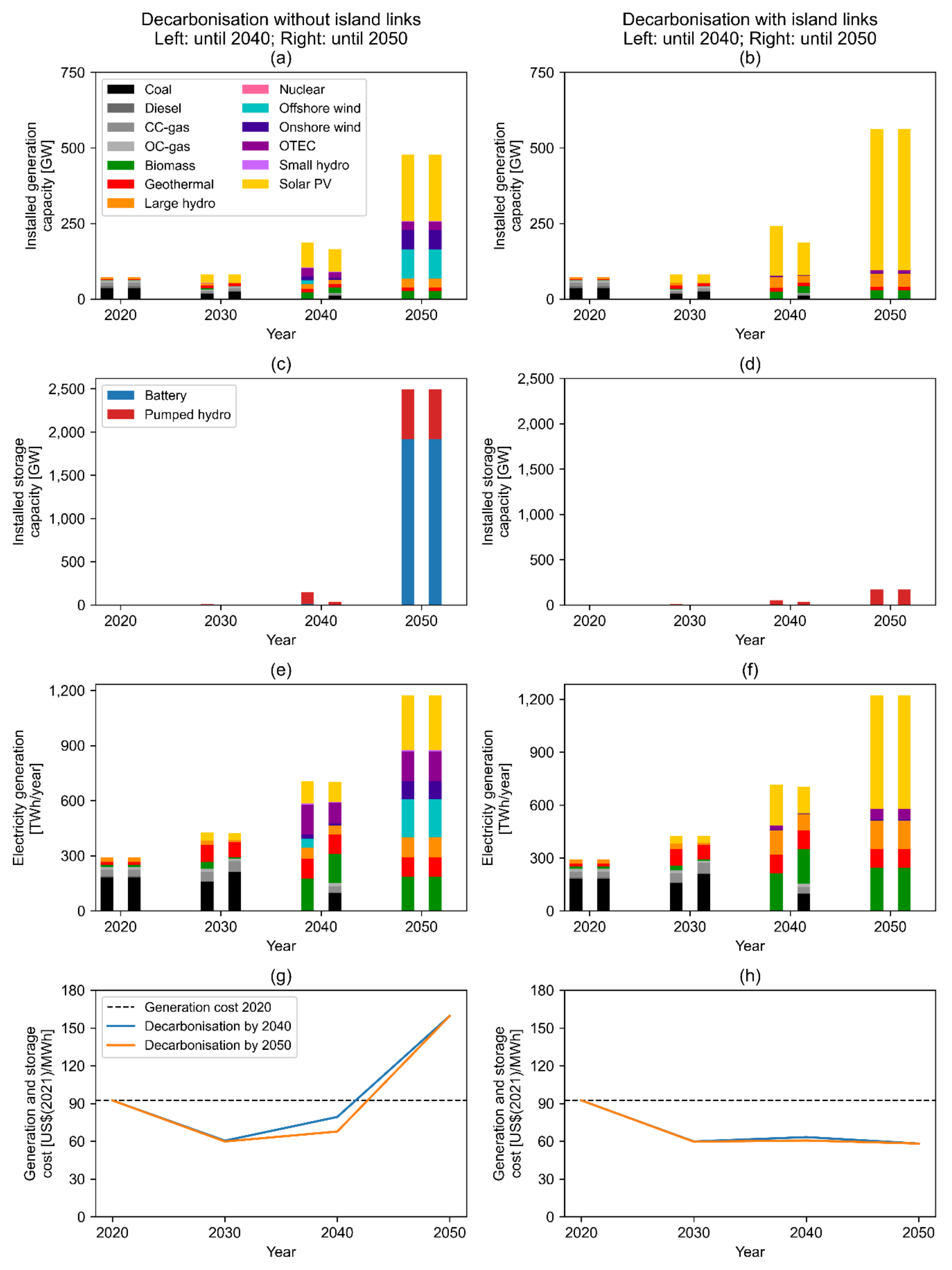


Figure 60. Installed (a, b) generation and (c, d) storage capacity, (e, f) electricity generation, and (g, h) levelised generation and storage cost of the decarbonisation pathways until 2040 (left bars) and 2050 (right bars) for the network topologies without (left column) and with (right column) island links.

Indonesia's power system could be fully decarbonised much faster than 2060 as currently pledged [9]. Both 2040 and 2050 are feasible targets, provided that decarbonisation starts now. The 2040 target would lead to fewer emissions in total, but poses more technical and economic challenges. The interconnected system would require 28 GW of sub-sea lines and 164 GW of PV capacity until 2040. For PV, that would mean a growth rate of 42% p.a. since 2020 (versus 32% p.a. globally between 2010–2021 [290]). Without island links, no sub-sea lines and less PV capacity are needed, but in turn large shares of renewables that are currently at conceptual (e.g., low-wind-speed offshore wind) and pre-commercial (e.g., OTEC) stages. Moreover, 74% of current coal capacity [268] would need to be retired up to twelve years earlier than initially planned (assuming 30 years of planned useful lifetime [280]), which might lead to high compensation costs to coal power plant owners.

Conversely, achieving the 2050 target would require a PV growth rate of 31% p.a. in line with global observations [290]. Also, only 35% of the 2020 coal capacity [268] would need to be decommissioned up to seven years earlier than planned, thus accruing lower compensation costs. Then again, the 2050 target would allow for 586 $MtCO_2e$ of greenhouse gas emissions after 2040 and is thus less ambitious in terms of climate change mitigation.

3.2. Island links secure supply via large shares of PV, backed by biomass, hydro, and geothermal

This section starts elaborating on the results of the scenario and sensitivity analysis. Figure 61 shows the impact of demand growth on the installed generation and storage capacity, generation, as well as generation and storage cost. Even at an increased 2050 demand of 3,240 TWh compared to the reference demand of 1,220 TWh in Figure 61(f), the interlinked system can meet all demand at almost the same levelised costs in Figure 61(h). Without island links, local renewable resources cannot meet demand on Java from 2030 onwards (indicated as "end of feasibility" in the left column of Figure 61). Note that 2050 demand projections can vary significantly in literature, from 950 TWh [28] to almost 3,000 TWh [29]. On the one hand, this shows that the increased demand growth in our study can indeed be called "extreme". On the other hand, we believe that such a demand is not entirely unrealistic if socio-economic development and the electrification of transport and industry, amongst others, advance rapidly. Then, island links would become a necessity prior to 2040 to ensure the security of supply.

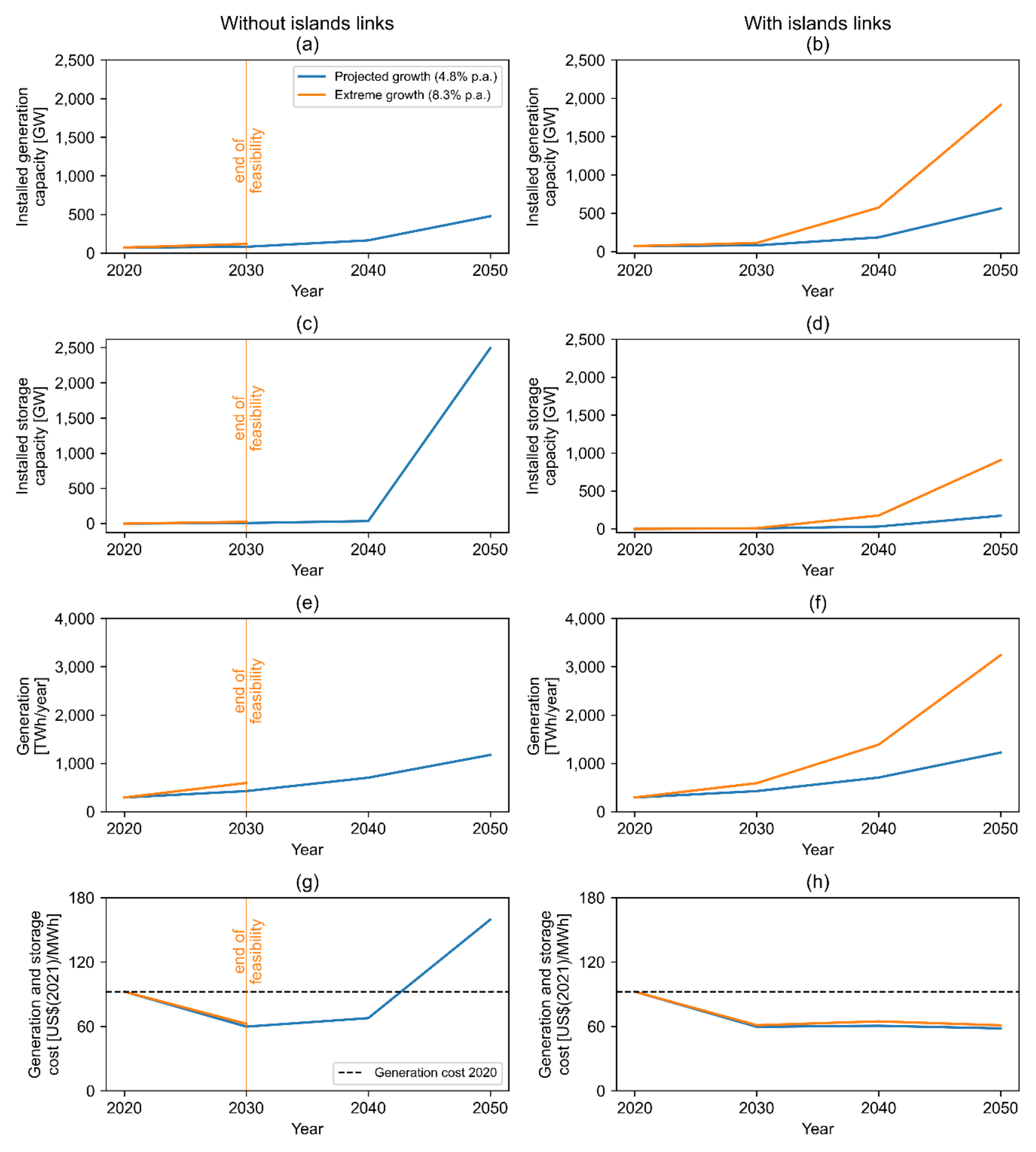


Figure 61. Impact of demand growth on installed (a, b) generation and (c, d) storage capacity, (e, f) generation, and (g, h) generation and storage cost of the full-decarbonisation-by-2050 pathway without (left column) and with (right column) island links.

Figure 62 compares the results of the alternative scenarios listed in Table 31 for the 2050 system with island links. Despite PV's dominance in most scenarios, baseload generation remains an important piece of Indonesia's power system. In all scenarios, the combined capacity and generation of biomass, large hydro, and geothermal is at least 77 GW in Figure 62(a) and 436 TWh/year, or 36% of total generation in Figure 62(c). Figure 63(b) shows that the deployment of geothermal and biomass is restricted by resource availability as their utilisation remains above 75% even if the available resources are doubled. In that case, baseload would account for more than half of total electricity generation in Figure 63(c). The official sources [5,341] used for the reference potentials of geothermal, biomass, and large hydro tend to underestimate available renewable resources [220]. Therefore, we recommend further research to better understand the potentials of biomass and geothermal, and refine their role in Indonesia's energy transition. In contrast, an increase in PV resources does not increase its deployment, showing that the omission of rooftop and floating PV did not affect the key messages presented here. In Box IV, we discuss the implications of omitting other RET, like wave and tidal power as well as concentrated solar power, on the results.

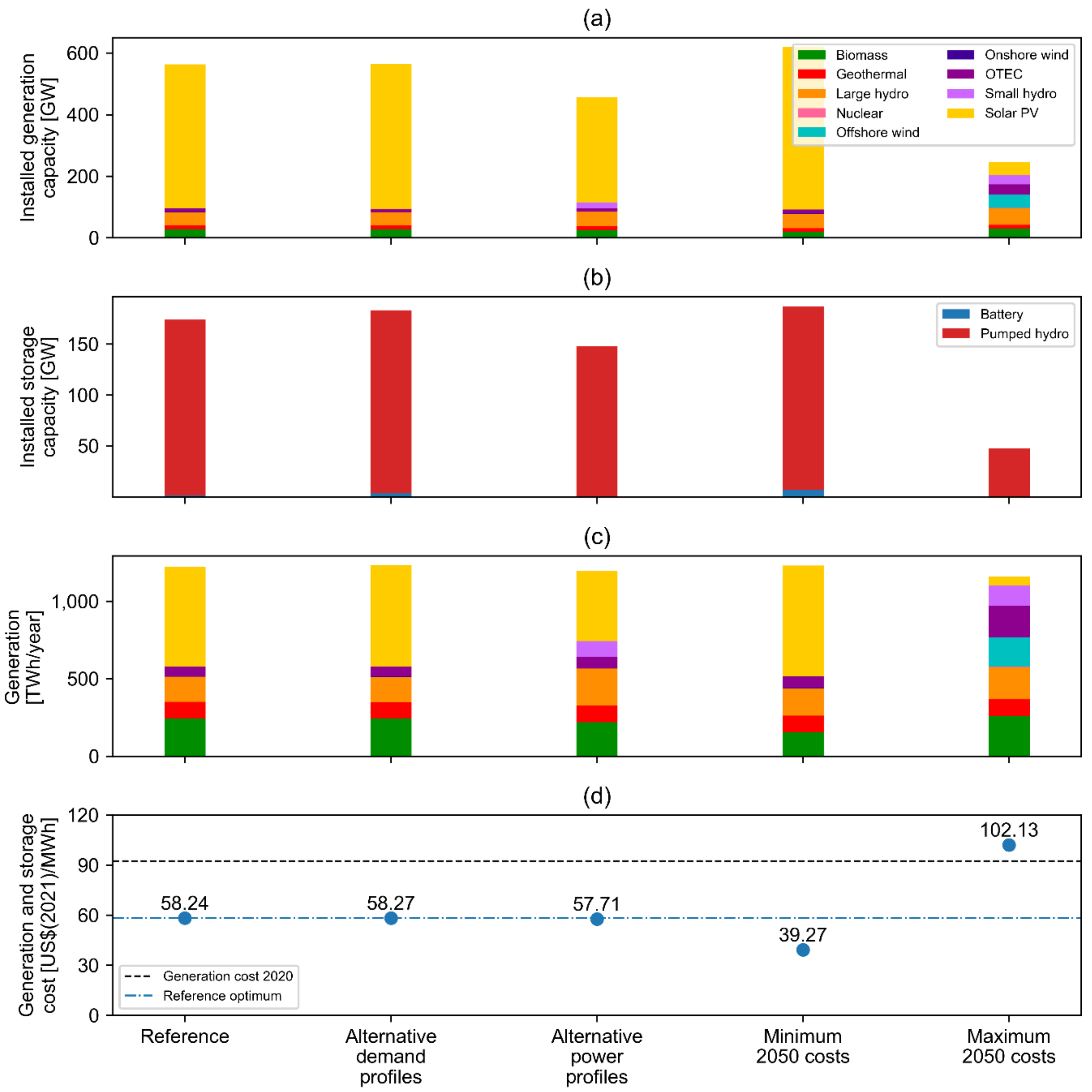


Figure 62. Installed capacity, generation, and total levelised cost of the network with island links in 2050 for the reference and alternative scenarios.

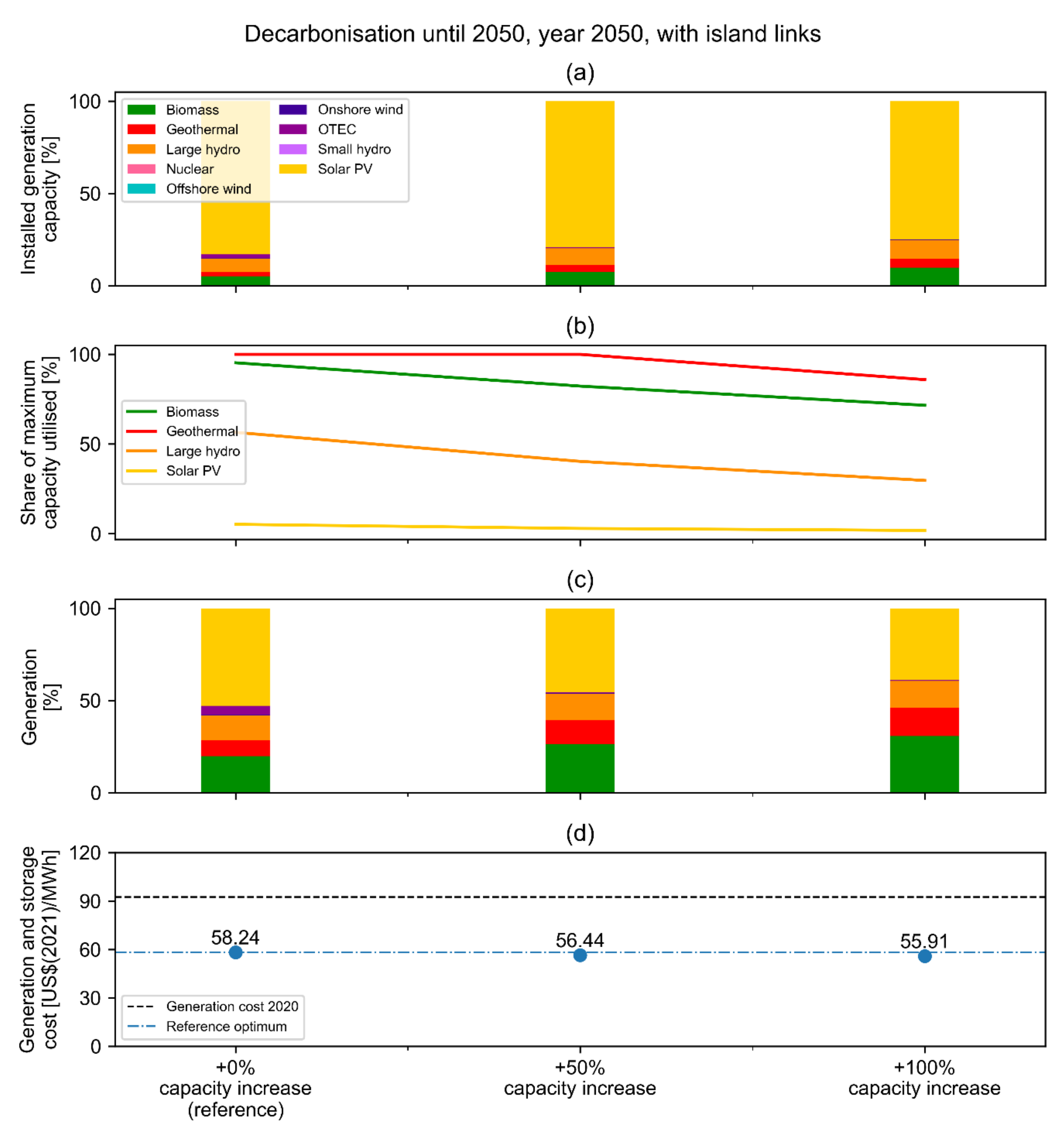


Figure 63. Sensitivity of modelling results to changes in renewable resource availability.

Box IV

Concentrated solar power (CSP)

We expect that the inclusion of CSP would not change the key findings presented here significantly. The site selection criteria of CSP and ground-mounted, utility-scale solar PV would be similar, so CSP would most likely have a high technical potential in most of Indonesia, but less so on Java due to land availability limitations. Without island links, CSP might be deployed on Java in favour of OTEC or offshore wind due to CSP’s lower CAPEX [290]. However, we do not expect that CSP could secure supply on Java if demand grows more strongly than in the reference case. As CSP would replace PV, not supplement it, the net increase in available RET resources would be determined by the difference between the two technology’s productivity. With island links, we would not expect CSP to be deployed in large quantities due to its higher CAPEX and lower cost reduction potential compared to PV [290].

Wave and tidal power

As reviewed in chapter 2, there are both wave and tidal power resources in Indonesia. While research suggests favourable wave energy resources along the South Javanese coastline, tidal power resources are more localised, e.g., at the Bali strait. Therefore, especially wave power could help Java to meet demand locally, at least to a certain extent. Just like with OTEC, wave and tidal power’s deployment will depend on how much their costs will decline in the future. Currently, LCOEs range between 300–550 US$/MWh for wave and between 200–450 US$/MWh for tidal. By 2030, wave is expected to 165 US$/MWh and tidal 110 US$/MWh [326]. If extrapolated to 2050, wave energy could be more cost-effective than OTEC and thus take its generation shares, at least where there are sufficient wave energy resources. Given the limitedness of available tidal power resources, we do not expect large generation shares even if LCOEs drop to competitive levels in the future.

In the “alternative power profiles” scenario in Figure 62, much less PV and pumped hydro capacity are deployed in favour of large and small hydro power. This scenario uses the power profiles from 2010, which is the year with the lowest PV and wind, but also highest hydropower productivity in the underlying 20-year dataset. This scenario underlines the importance of a diversified generation portfolio that is hedged against times of less sunshine, wind, and rainfall. In contrast, the shape of the demand profiles in the “alternative demand profiles” scenario only has a marginal influence on the systems’ key indicators, thus justifying the use of Malaysian data.

Figure 62 further shows that the use of more conservative 2050 cost projections have a massive effect on the resulting system configuration and costs. While the system configuration of the “minimum 2050 costs” scenario is fairly similar to the reference system, the one from the “maximum 2050 costs” scenario shows clear differences. If maximum 2021 costs are coupled with the lowest cost reduction rates in literature, PV’s 2050 CAPEX and OPEX would remain at 1,500 US$(2021)/kW$_p$ and 18 US$(2021)/kWp/year in 2050. This would lead to a PV generation share of only 5%, while the rest is provided by a diverse mix of technologies, including high shares of offshore wind and OTEC.

But how likely is such a scenario? According to IRENA [290], PV's costs decreased at an unprecedented rate globally, from a weighted average of 4,808 US$(2021)/kW$_p$ in 2010 to 857 US$(2021)/kW$_p$ in 2021. For Indonesia, the same report states weighted average costs of 1,264 US$(2021)/kW$_p$, which is above the global average, but below the CAPEX used in the "maximum 2050 costs" scenario. Assuming median 2050 costs for all other technologies, Figure 64 indicates that PV's costs would need to drop to roughly 658 US$(2021)/kW$_p$ by 2050 to reach a PV generation share of 50%. Such cost levels are realistic given that recent quotations for a PV plant in Sulawesi already reached average costs of 690 US$/kW$_p$ [276]. Hence, we see the "maximum 2050 costs" scenario less as a realistic possibility, but more as a cautionary tale about choosing cost assumptions wisely for energy system modelling.

Nonetheless, Indonesia's PV industry needs to further mature to attain substantial and widespread cost reductions. PV generation only accounted for 176 GWh, or 0.06% of total generation in 2020 [235]. One barrier is the minimum local content restriction on PV panels for commercial power plants, while domestic manufacturers cannot yet provide the PV capacities needed for deep decarbonisation. Therefore, gaining access to affordable high-quality panels from international markets might reduce costs to the abovementioned levels [13]. As outlined by MENTARI [354], an alternative could be to temporarily lift import measures on PV panels while scaling up the domestic industry. Once manufacturing capacity is on-par with demand, the import restrictions could be reintroduced.

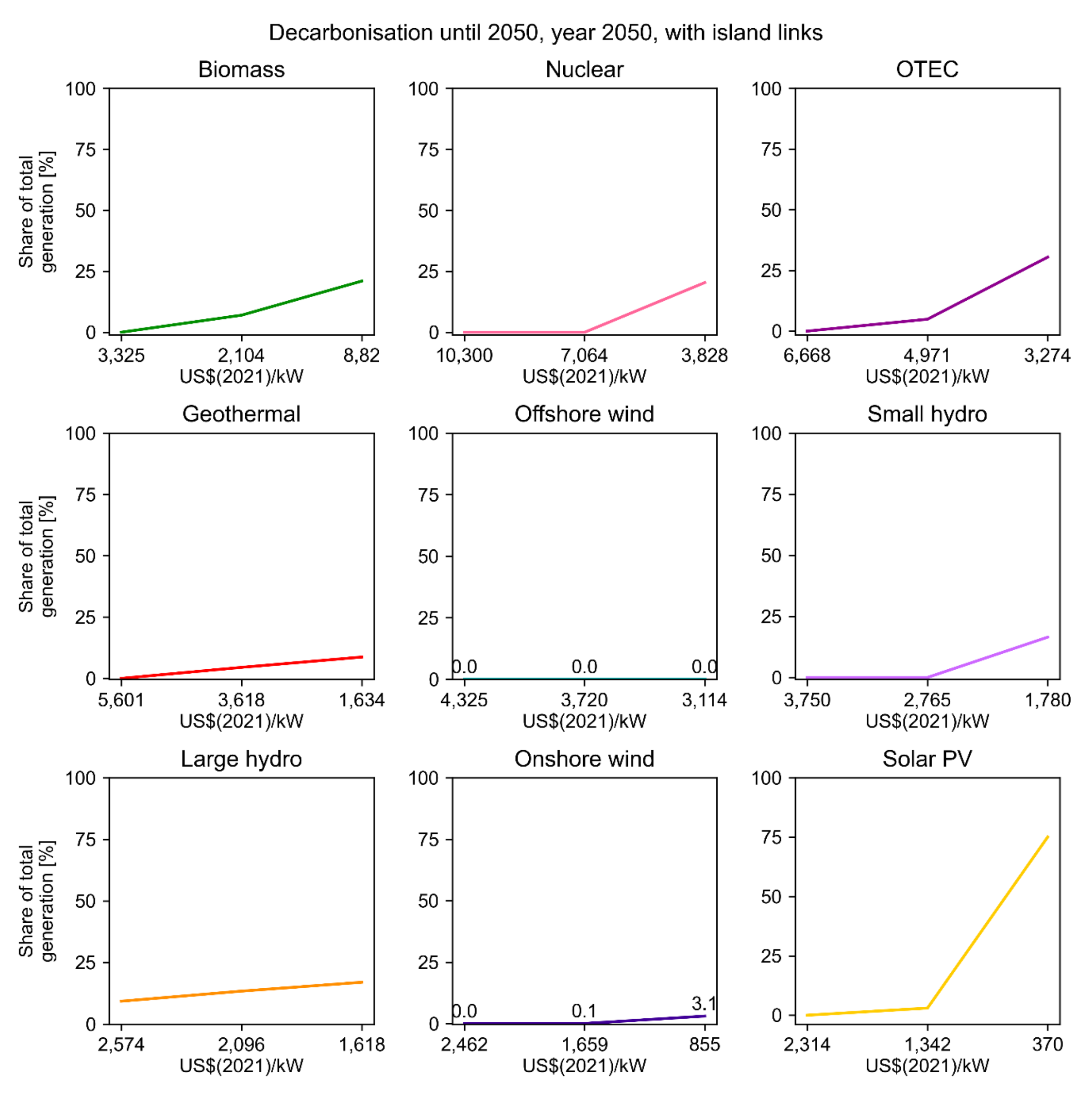


Figure 64. Sensitivity of generation shares to changes in individual technology costs. For each panel, we change the costs of the studied technology from maximum 2021 to minimum 2050 levels, while keeping the costs of all other technologies at median 2050 levels.

Figure 64 shows that nuclear and OTEC would only have noticeable generation shares if they experience extreme cost reductions until 2050 (i.e., minimum 2050 costs). For OTEC, we see a hen-and-egg problem as it needs strong and sustained cost reductions to be considered by the model, but these cost reductions are only achieved if there are early adopters who implement OTEC at its pre-commercial, high costs. Therefore, OTEC's commercialisation might require public support to encourage early adoption. Otherwise, Indonesia can resort to other renewables if OTEC fails to develop towards commercial scale in time. At minimum 2050 levels, 28 GW of nuclear could provide 20% of total electricity generation. This contrasts the 121 GW of nuclear capacity from Reyseliani & Purwanto's [41] 100% RET + nuclear scenario, which most likely used different costs and implementation restrictions (if any). Figure 64 further indicates that both onshore and offshore wind are not cost-effective technologies in our model even under strong cost reductions and with island links, which can be explained with the low wind speeds in most parts of Indonesia [47]. However, these technologies might still be relevant in the sub-provincial energy transition at hotspots with high onshore and offshore wind speeds.

3.3. Kalimantan could become a major power provider to Indonesia

This section focusses on the island links and their sensitivity to more conservative technical and economic assumptions. Figure 65 illustrates the installed transmission capacity between islands in 2050 for the (a) reference and (b) extreme-demand scenario.

Our findings show that Kalimantan would become a major power provider of Indonesia with 35–38% of total electricity generation. Under current demand projections (4.8% p.a.), the total installed inter-island transmission capacity would be 49.5 GW. For comparison, the sub-sea transmission capacity installed on the European continent in 2015 was already about 14 GW [355], and expected to grow substantially by 2050, despite Europe not being an archipelagic entity. Therefore, the obtained number can be deemed plausible. Under extreme demand growth (8.3% p.a.), 248 GW of inter-island transmission capacity would be necessary, including several 50 GW links to Java.

Such large lines are mainly the result of setting the maximum installable capacity per island link to 50 GW. As shown in Figure 66, the reference scenario deploys lines of up to 16 GW and distributes the total needed transmission capacity over more lines if maximum capacity per line is capped to lower thresholds. If electrification and sector-coupling progresses and electricity demand grows more strongly than in the reference scenario, Indonesia has several options to distribute the transmission capacity to avoid too large transmission links.

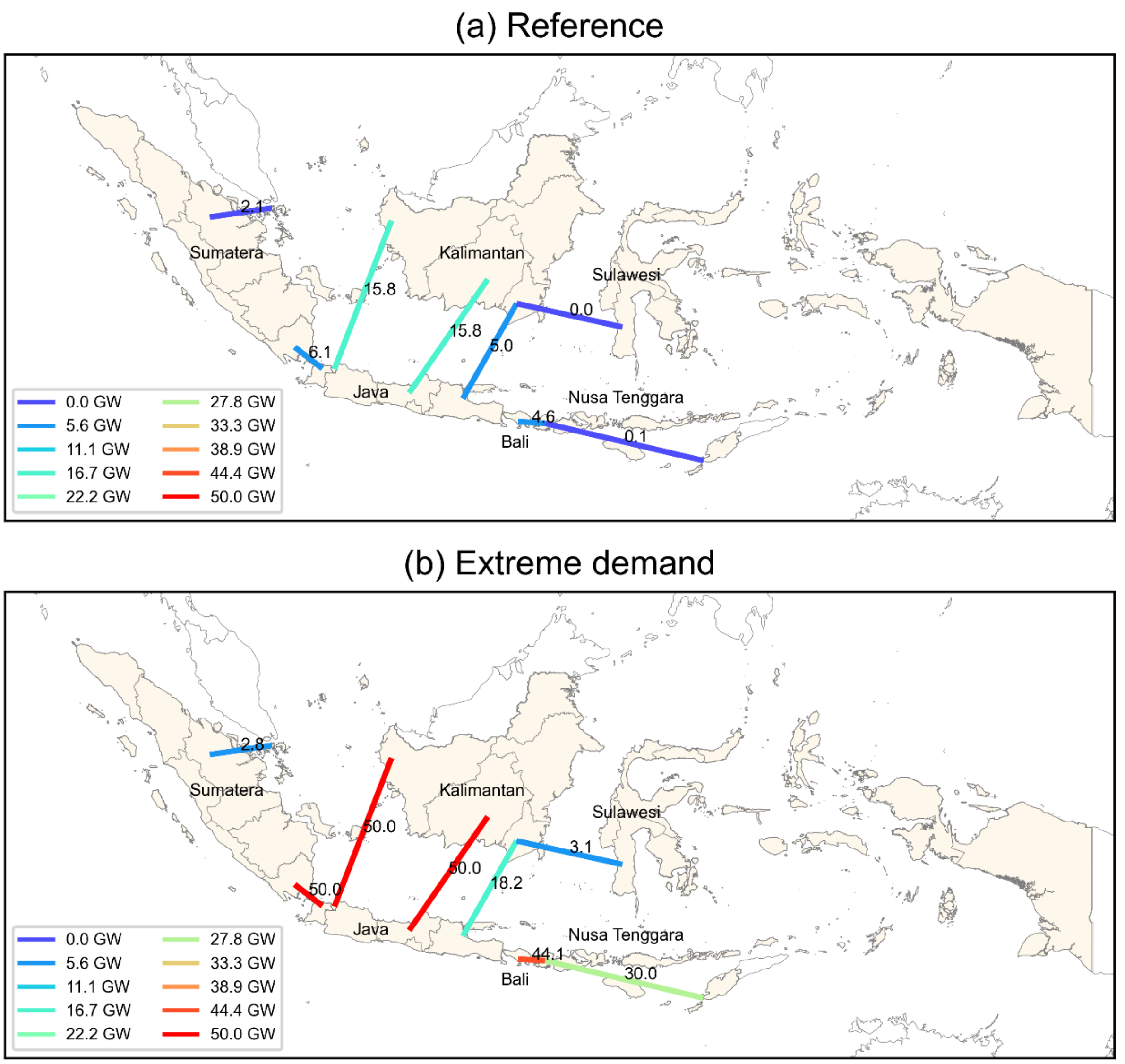


Figure 65. Active power flows of island links for the (a) reference and (b) extreme demand scenarios. The line colours reflect the rated line capacities.

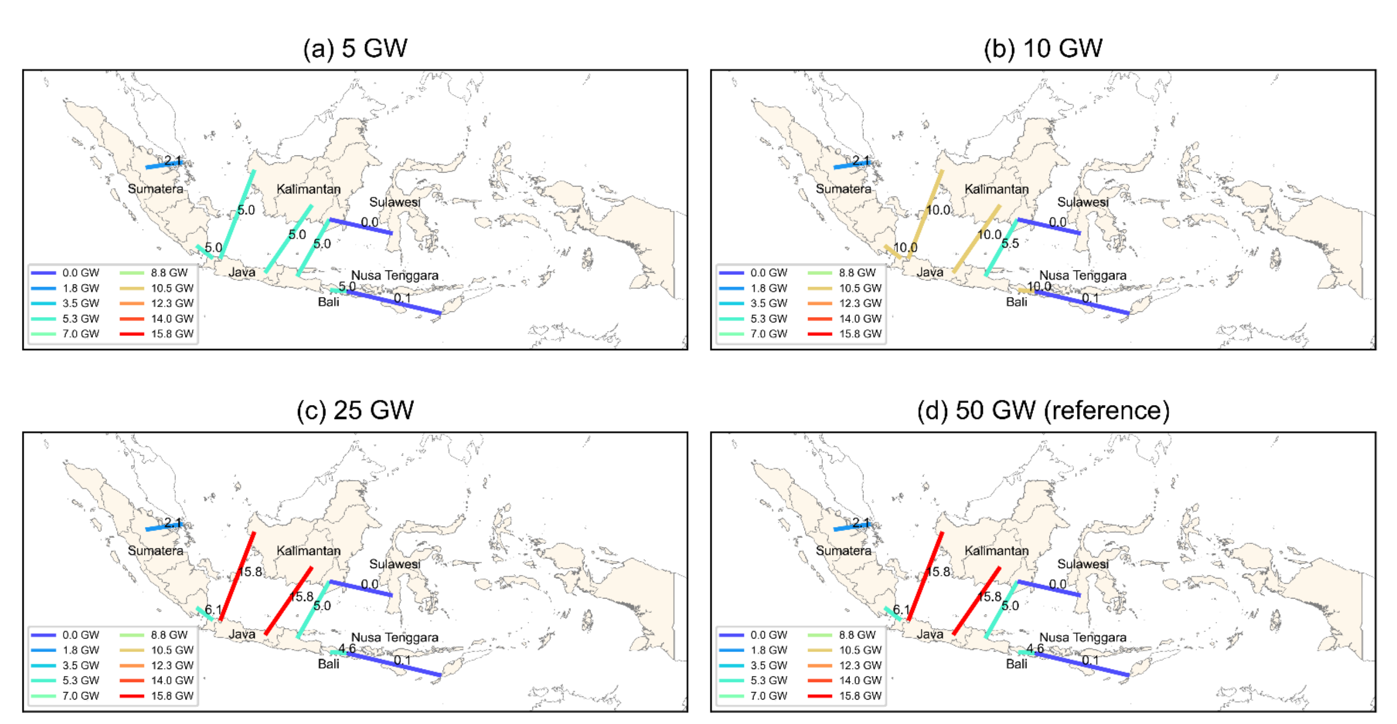


Figure 66. Sensitivity of island links to changes in maximum sub-sea transmission capacity between provinces.

Figure 67 illustrates how island links remain relevant even under significantly higher costs. If sub-sea cable costs increase by more than double, as shown in Figure 67(c), certain links, such as the Nusa Tenggara–Bali link, are no longer utilized. The links from West and Central Kalimantan to Java are only moderately affected, with their combined capacity decreasing from 31.6 GW to 27.8 GW. This underlines the pivotal role of the Kalimantan–Java links in Indonesia's full power system decarbonisation. Conversely, certain links, like the Sulawesi–Kalimantan connection, are not deployed in any of the scenarios, so they could be prioritised less when planning Indonesia's interconnected grid.

Figure 68 shows that our key findings stand against more conservative transmission assumptions. PV and pumped hydro remain major technologies, with large amounts of electricity being sent from Kalimantan to Java. Nonetheless, we see a slight shift towards local generation with the increased shares of OTEC on Java, especially under higher inter-island transmission costs. Despite the significantly higher costs from transmission and OTEC generation, the total system costs (i.e., generation, storage, and transmission) only increase slightly from 64 to 70 US$(2021)/MWh.

What our model does not capture are the non-technical challenges of island links. Indonesia consists of more than 17,000 islands with different cultural, political, and institutional contexts. Setyowati and Quist [4, p.9] showed that "energy planning processes are not neutral technical exercises but constitute political processes […] at national and subnational levels". Therefore, national interconnections might stand in contrast with the desire of subnational islands to maintain their energy independence, amongst others. Since interconnections could be a source of income for regions like Kalimantan, our results could be used to highlight the mutual benefits of such interconnections and to reconcile them with local values.

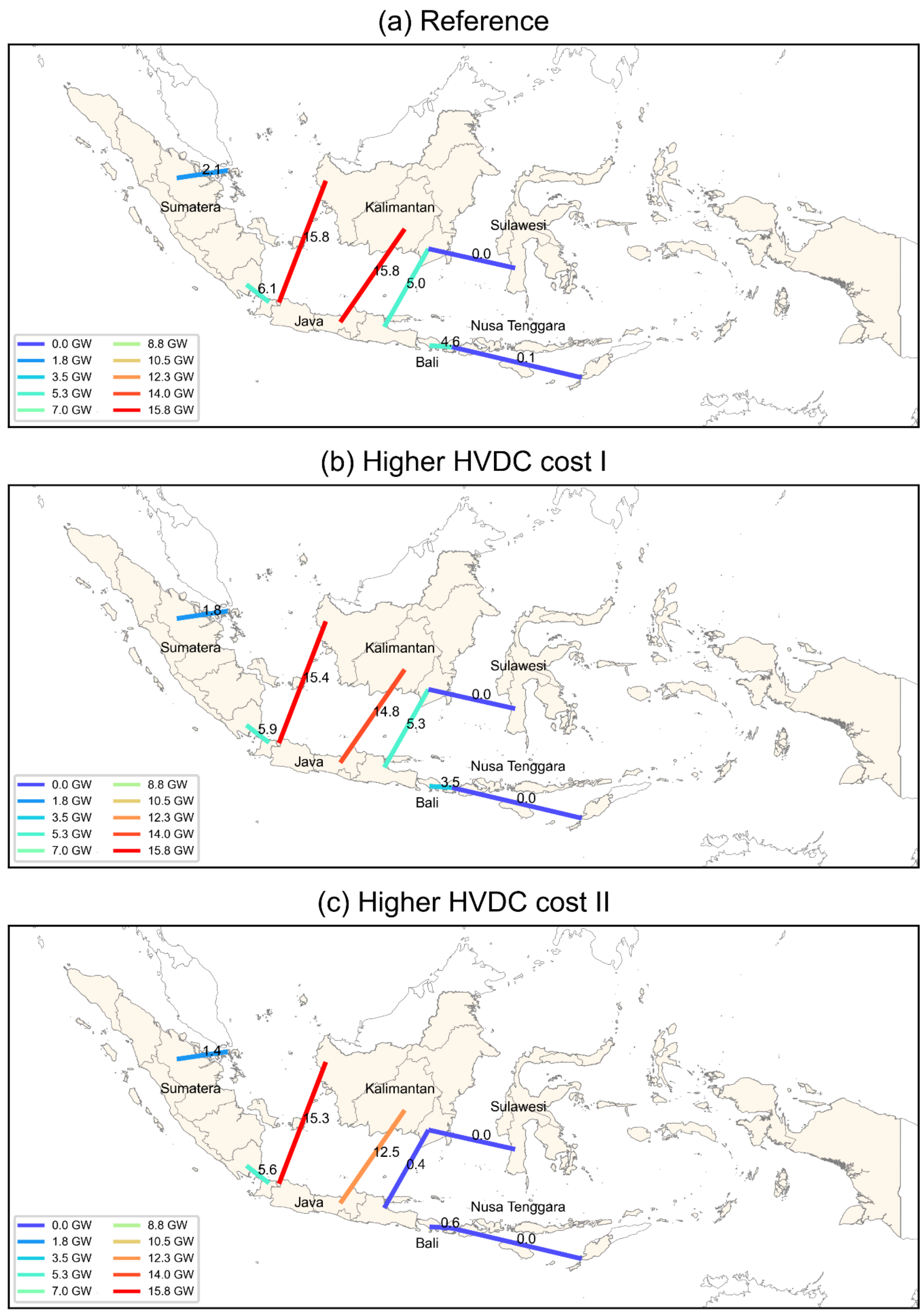


Figure 67. Sensitivity of island links to changes in CAPEX and OPEX of sub-sea transmission lines in 2050. (a) CAPEX: 870 US$(2021)/MW and OPEX: 2.5 US$(2021)/MWh, (b) CAPEX: 1,435 US$(2021)/MW and OPEX: 4.25 US$(2021)/MWh, (c) CAPEX: 2,000 US$(2021)/MW and OPEX: 6 US$(2021)/MWh

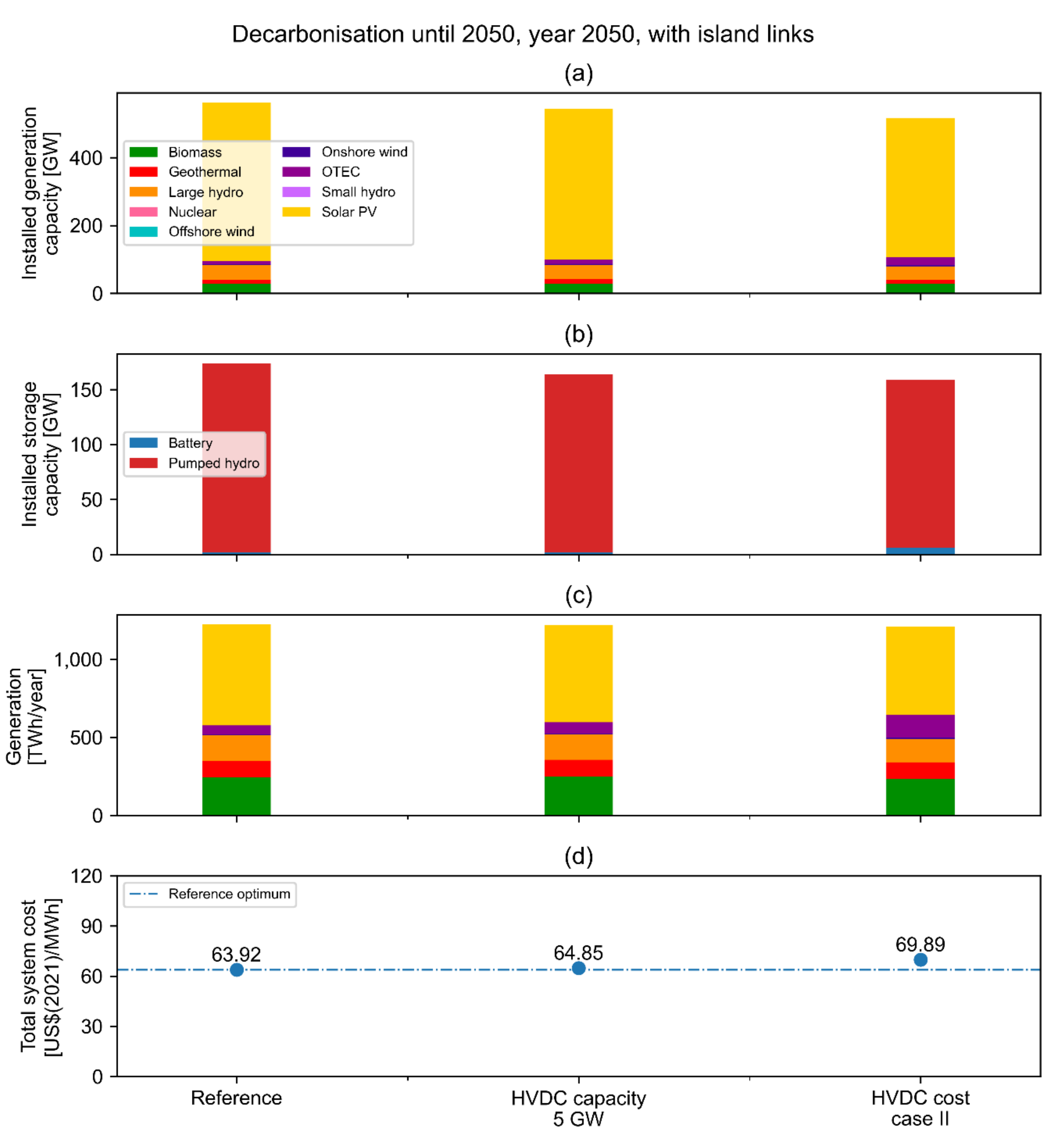


Figure 68. Impact of transmission capacity and cost on installed (a) generation and (b) storage capacity, (c) electricity generation, and (d) total system costs (i.e., generation, storage, and transmission costs).

Furthermore, our study does not consider the intricacies of sub-sea cable routing with regards to seismic activity, shipping routes, etc. and their impact on power system planning. As depicted in Figure 69, Indonesia is on a high tectonic setting with many seismic faults that can cause devastating earthquakes and tsunamis, like the Palu Earthquake in 2018 on Sulawesi [356]. Thus, high seismic design criteria need to be considered carefully to ensure the sustainable and long-lasting operation of both sub-sea links (especially the links connecting Java–Sumatera, South Kalimantan–East Java, and Java–Bali–West Nusa Tenggara) and on-land links, especially considering the seismic activity on Sumatera (Great Semangko Fault), Sulawesi (Palu-Koro Fault), Java (Baribis Fault), and East Kalimantan [357].

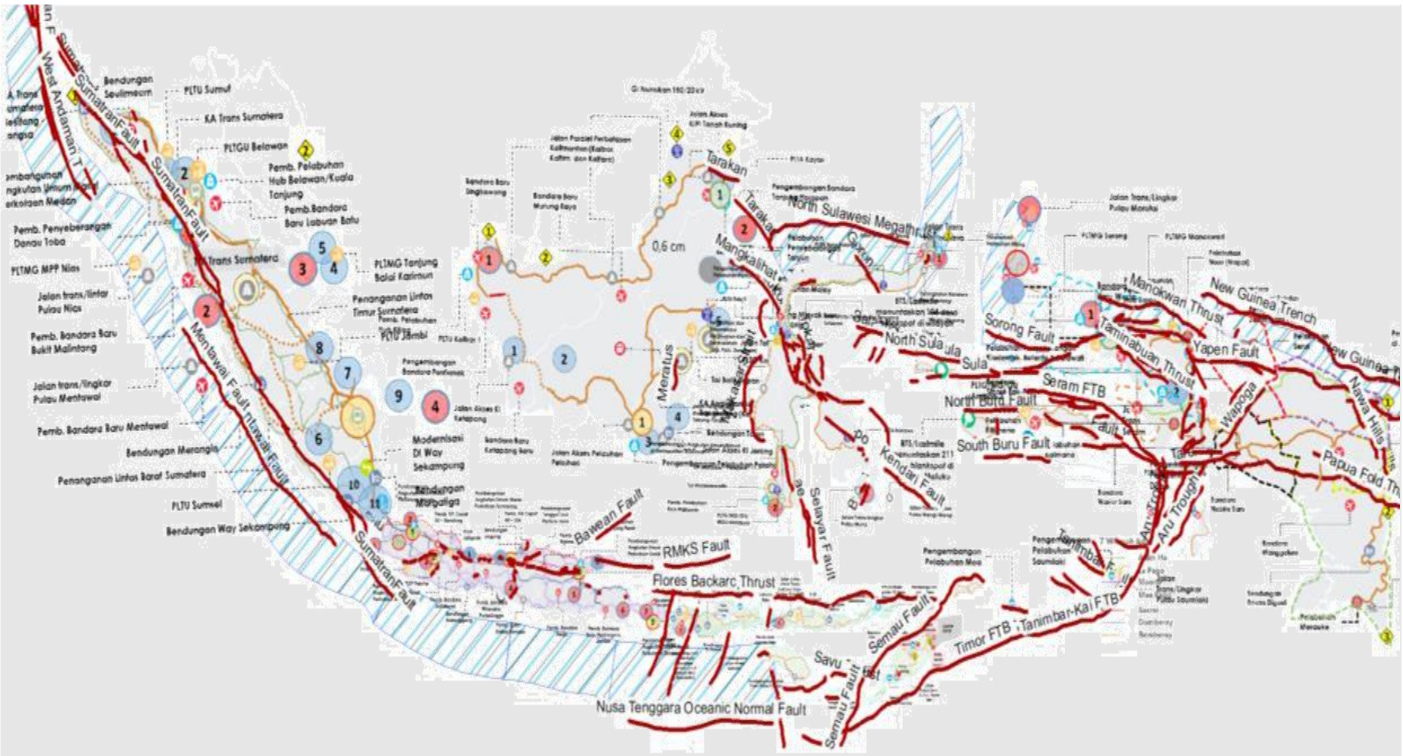


Figure 69. Indonesia's tectonic setting [357].

Nonetheless, our results show that island links are key for Indonesia's energy security once power system decarbonisation gains momentum as demand could be met domestically, reliably, and affordably even under strong demand growth. Beyond Indonesia, our findings could be relevant for the planned ASEAN power grid [358] connecting Indonesia to neighbouring countries like Singapore and Malaysia, and for the conceptualisation of a global grid connecting all inhabited continents.

4. Conclusions

This chapter explores full decarbonisation options for Indonesia's power sector. We address current limitations in Indonesian modelling literature by using the spatially and temporally resolved state-of-the-art energy system optimisation model Calliope. The model considers various techno-economic assumptions, electricity network topologies, and scenario designs. Despite its focus on Indonesia, the chapter is globally relevant as our findings might translate to other island and archipelagic states, as well as the ASEAN region.

Our results show that Indonesia has several diverse options to fully decarbonise their power sector, with some being more preferable than others in terms of costs. Indonesia has the potential to achieve full decarbonisation of its power system well before the currently pledged 2060 timeline provided that decarbonisation starts now. The 2040 target would avoid 586 $MtCO_2e$ of emissions compared to the 2050 target, but also poses greater technical and economic challenges in terms of renewable capacity upscaling and premature phase-out of existing fossil-based capacity. If local future cost reductions follow global trends, 468 GW of solar PV would produce roughly half of total electricity in 2050, coupled with 172 GW of hydroelectric energy storage (pumped hydro). For PV, these cost reductions could be materialised with the temporary lift of import restrictions on PV panels while ramping up domestic panel manufacturing capacity.

The establishment of 50 GW of inter-island power transmission links would be a substantial step in maintaining levelised generation and storage costs of roughly 60 US$(2021)/MWh by supplying high-demand regions like Java with low-cost electricity, e.g., from Kalimantan. These island links remain essential under higher costs and capacity restrictions. Following current demand growth projections, Java could also meet its demand locally, but only with inclusion of early-stage, capital-intensive technologies like OTEC, as available land for PV and pumped hydro is limited on Java. If demand grows more strongly, e.g., via the electrification of transport and industry, island links become crucial as local resources on Java alone would no longer suffice to meet demand. Biomass, large hydro, and geothermal are another key element of Indonesia's decarbonised power system with a combined capacity and generation share of at least 77 GW and 36% of total generation. As baseload generators, especially geothermal and biomass are mainly limited by local resource availability rather than economic limitations.

We conclude that Indonesia's energy transition is not primarily a matter of technology and resource availability, but of investment, political will, and commitment. Once the main islands are interconnected, Indonesia's decision makers may have the luxury of deciding between a diverse set of equally viable system configurations of their preference. However, there will be challenges. Indonesia must provide a conducive environment for domestic and international investments into new, renewable generation, storage, and transmission infrastructure, as well as the retirement of fossil capacity. Moreover, the energy transition must be socially just and inclusive. Regions currently reliant on the coal industry must not be left behind and included in a decarbonised world, e.g., as a hub for renewable energy services for Kalimantan. The sovereignty of subnational islands must be respected, and the establishment of island links must be based on mutual benefits.

This chapter already offers a diverse set of solutions for Indonesia's power system decarbonisation. Nonetheless, the model can be further improved by addressing the limitations of our work. The model could be expanded to other energy carriers (e.g., hydrogen), sectors (e.g., transportation and industry), and technologies. Further research into these matters might strengthen the benefits of island links, not only for electricity, but other gaseous and liquid energy carriers. Then again, technologies like carbon capture and storage, wave power, and tidal power could be included to offer more options for Java to meet demand locally. Furthermore, the model could be further developed to account for the costs of power infrastructure already existing before the modelled year. Lastly, the sub-sea cable routing of the island links could be researched in more detail, considering limitations from areas with seismic activity and shipping routes, amongst others.

8. Conclusions, Discussion, and Recommendations

1. Research outcomes

In this section, we first provide an overview of the overall results and answer the main research question, followed by the sub research question to provide further context.

"What is the technical and economic potential of variable RET for power generation in Indonesia and how could RET contribute to a fully decarbonised power system?"

From the literature review conducted in chapter 2, we found that RET potentials in Indonesia are large in principle, but not yet refined in terms of (1) resource availability on a national level, (2) economic potentials, (3) the potential of ocean energies like offshore wind and OTEC, as well as (4) the utilisation of RET potentials from a power system perspective. This dissertation addresses these knowledge gaps by mapping the national technical and economic potential of variable RET across Indonesia at a high spatial and temporal resolution and by exploring full power system decarbonisation scenarios with the energy system model Calliope.

Table 33 summarises the technical and economic potentials mapped within and outside of this PhD project, namely for ground-mounted utility-scale solar PV, onshore and offshore wind, as well as OTEC. The technical potential of these four technologies reaches up to 22 PWh/year, covering Indonesia's projected 2050 demand 7–23 times (lower limit based on Ref. [29], upper limit based on Ref. [28]). As visualised in Figure 70, the technical RET potentials are spread over almost all parts of the country. This is especially visible for offshore wind and OTEC as there are few offshore areas in Indonesia where neither technology is technically feasible. However, there are bottlenecks for RET deployment, especially on Java. There, most land is not accessible for RET like ground-mounted PV due to restrictions from built-up infrastructure, agricultural land, forests, water bodies, and volcanoes, amongst others. For RET like onshore wind, such bottlenecks could be alleviated by combining wind farms with other land uses as investigated in chapter 4. For PV studied in chapter 5, the possibilities for combined land use are much more limited, leading to a relatively small technical PV potential on Java compared to the large potentials in other parts of the country where more land for PV is available.

Table 33. Summary of technical and economic potentials of RET in Indonesia mapped in our own work within and outside of this dissertation. BPP: Biaya pokok penyediaan translates to basic costs of electricity provision and reflects the costs of generating one unit of electricity. Until 2022, the BPP was used as a benchmark to determine ceiling tariffs for renewable power generation.

Technology	Technical potential [TWh/year]	Economic potential [TWh/year]	Notes	Chapter	Ref
Solar PV	12,200	3,400	• Only open, unused land • Capacity density: 60 MW_p/km^2 • Economic potential using minimum BPP since 2017	5	[13]
Onshore wind	210–2,000	20–130	• Lower limit: only open land; upper limit: open land, agriculture, forestry, conservation zones • Economic potential using 2021 BPP	4	[45]
Offshore wind	6,800	750	• Economic potential using 2019 BPP	3	[232]
OTEC	1,400	16	• Sites inside exclusive economic zones • Economic potential using 2019 BPP • Technological learning excluded	6 (Boxes II & III)	[18,19]
Total	**19,800–21,500**	**4,100–4,300**	**–**	**–**	**–**

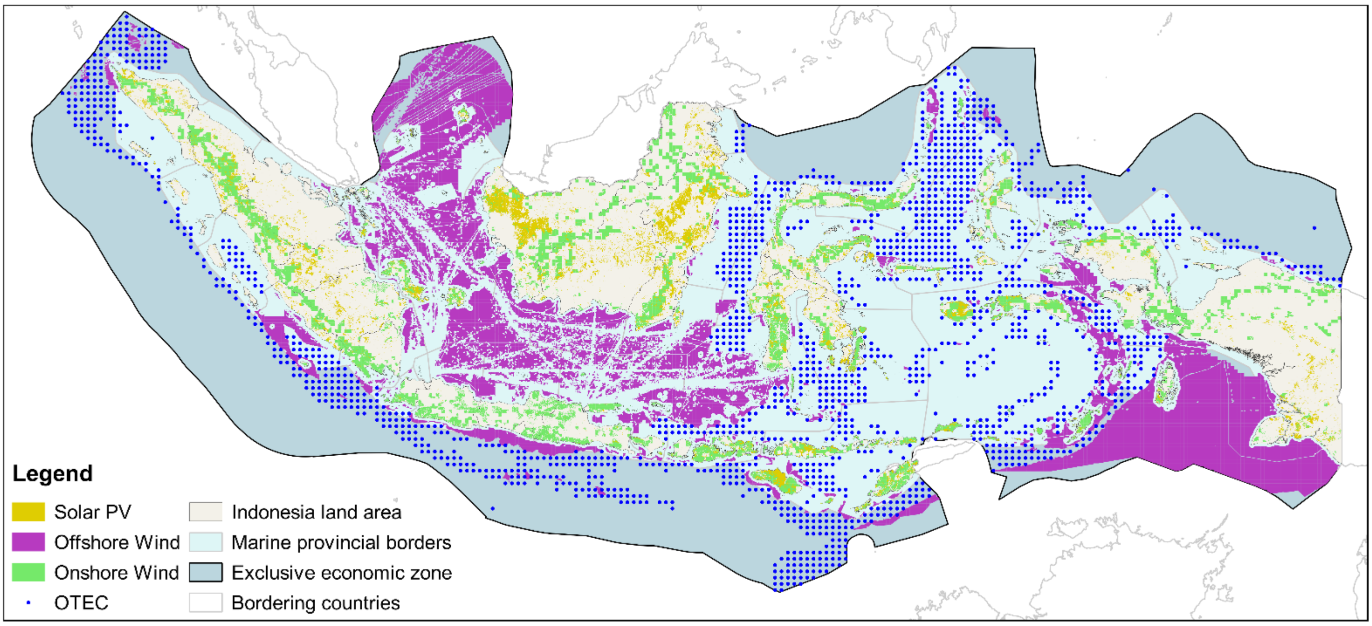


Figure 70. Technical potentials of renewables in Indonesia mapped within and outside of this PhD project [13,18,19,45,232].

Figure 71 shows the economic RET potential in Indonesia. In principle, the total economic potential is high with up to 4.3 PWh/year, covering projected 2050 electricity demand 1.4–4.5 times (lower limit based on Ref. [29], upper limit based on Ref. [28]). However, the economic potential is almost exclusively located in East Indonesia, where electricity demand is relatively low with an expected 2030 demand of 16 TWh, or 3.6% of national 2030 demand [9]. The tariff scheme applicable during most parts of the PhD project was based on local generation costs, which are higher in the East due to expensive diesel generators than in more developed regions where subsidised coal is mainly used. With this scheme, RET faced an uphill battle as they only received up to 85% of the generation costs of subsidised fossil generators. The economic potential could be spread to the rest of the country where demand is higher via different policies, e.g., a carbon tax of 100 US$(2021)/t$CO_2$e for onshore wind in chapter 4, as well as a nationwide feed-in tariff of 11.5 US¢(2021)/kWh and the lift of import restrictions for solar PV panels in chapter 5.

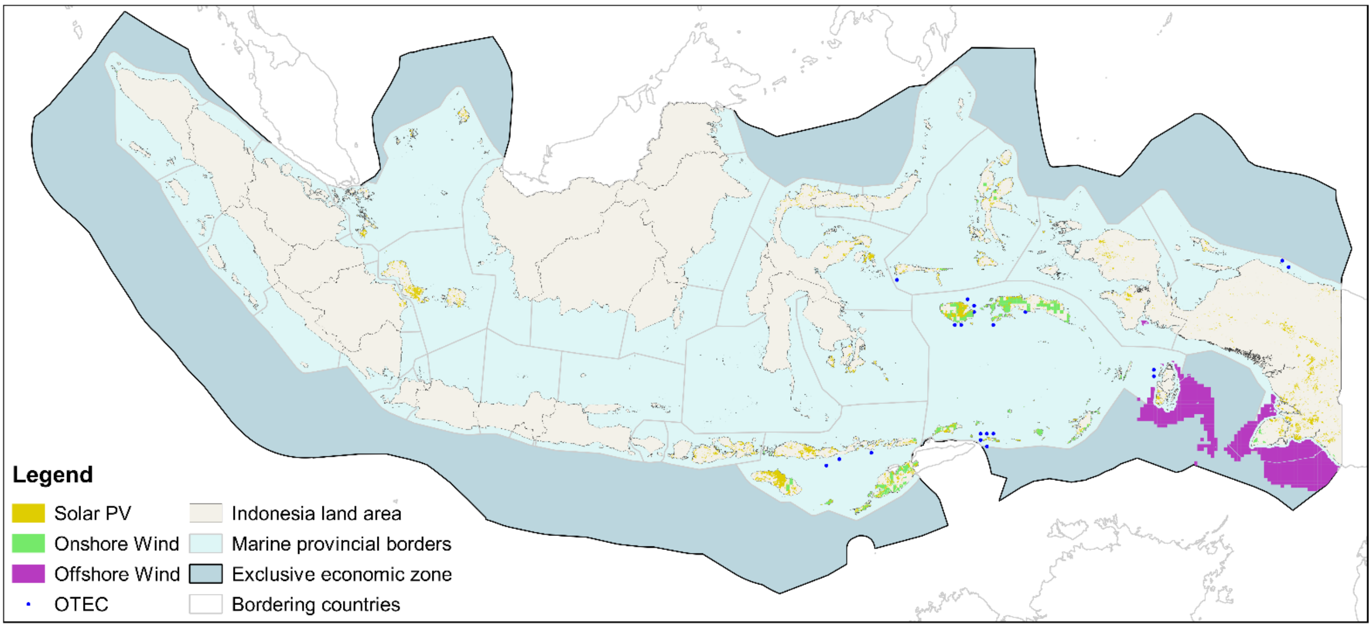


Figure 71. Economic potentials of renewables in Indonesia mapped within and outside of this PhD project [13,18,45,232].

Indonesia's technical RET potentials allow for an array of diverse options for full power system decarbonisation, although some options are more preferable in terms of cost-effectiveness than others. Available RET potentials are large enough to meet all demand even if demand grows extremely by 8.3% p.a., reaching 3,240 TWh in 2050. In that case, however, the RET resources on Java and Bali do not suffice to meet demand locally due to the abovementioned limited available land, and sub-sea power cables to other islands are needed. In the reference scenario (with demand growth rate of 4.8% p.a., reaching 1,220 TWh in 2050), Java could technically meet demand locally, but it is still more cost-effective to deploy island links as this allows Indonesia to tap into its most cost-effective RET resources to meet demand. A power line from East Indonesia to Java, as suggested by the economic potentials in Figure 71, is not necessary as it is more cost-effective to connect Java to the closer islands Kalimantan and Sumatera. With 50 GW of inter-island transmission capacity, solar PV becomes the dominant technology by 2050 with a generation share of more than 50% and an installed capacity of 468 GW, accompanied by 172 GW of pumped hydroelectric energy storage. Other important generators are biomass, reservoir hydro, and geothermal, with at least 77 GW and 36% of installed capacity and generation share, respectively. Other technologies like nuclear and

OTEC also see implementation by the model, but only if significant cost reductions by 2050 are achieved. Onshore wind is interesting locally where wind resources are strong enough, while offshore wind did not see implementation even under strong cost reductions. Regardless of the deployed RET, we find that the first essential step towards decarbonisation is the retirement of Indonesia's fossil-fuel-based capacity. Once retirement sufficiently progressed, the deployment of large-scale RET and sub-sea island-interconnections kicks in from 2030 onwards in our model. Our research also showed that full decarbonisation could be achieved much earlier than 2060 as currently pledged, with Figure 72 sketching a roadmap with measures to achieve such decarbonisation.

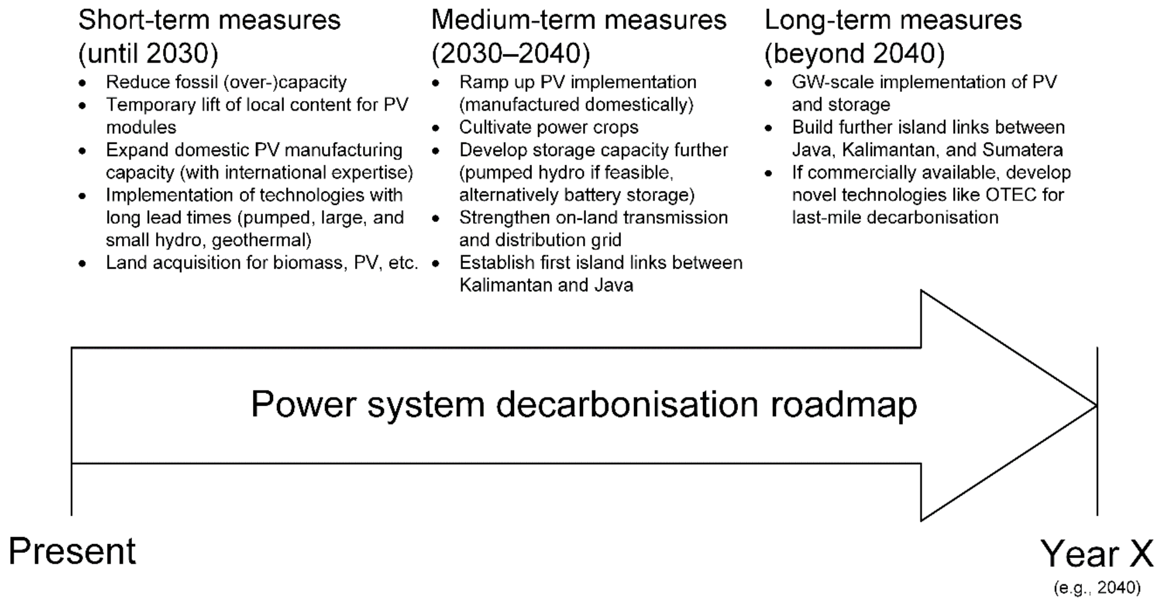


Figure 72. Roadmap for Indonesia's power system decarbonisation based on this dissertation's findings.

The answers to the sub research questions are as follows:

1. *What is the current understanding of renewable energy potentials in Indonesia in academic and non-academic literature and how much present and future demand could they cover?*

Chapter 2 lays the groundwork of this dissertation and reviews contemporary literature on RET potentials in Indonesia and how they could contribute to meeting current and future electricity demand. We distinguish between the theoretical, technical, and economic potential, which build on each other and use increasingly restrictive criteria.

The existing body of knowledge indicates large amounts of RET resources on land and sea in Indonesia. Even after accounting for unavailable or unsuitable areas for RET deployment, the remaining, technically feasible potentials suffice to fully cover 2050 electricity demand. The combined technical potentials of solar PV and offshore wind of 43 PWh/year from scientific literature could cover 2050 demand 19 times. Adding other RET, like geothermal, biomass, and OTEC, Indonesia's future electricity system could be fully built around RET.

However, we detected three knowledge gaps in the reviewed literature. First, there is little research covering the entire country beyond the technical potential. Most nationwide potentials originate from official sources, for which used data and methods are not fully disclosed. Moreover, official PV and onshore wind potentials might be too conservative given the available information. Peer-reviewed studies mostly focus on local case studies that may not scale to the whole country. If resources were mapped for entire Indonesia, then usually as part of global analyses with limited spatial resolution and/or local context. The reviewed literature also barely touches upon the current and future economic feasibility of RET.

Second, existing works do not frame the potentials into the context of competing technologies and the electricity system as a whole. They only focus on one technology and do not reflect on the aggregated potential and complementarity of RET in Indonesia. On a system level, it remains unclear how much of the potentials is needed to meet future demand cost-effectively. Existing studies that model Indonesia's future electricity system mainly use official potentials, thus carrying the potentials' conservatism over to their analyses.

Third, existing studies lack thorough field data for RET resources and do not make use of state-of-the-art alternatives, like global reanalysis datasets. The data collected for the reviewed studies, e.g., via local wind-speed measurements, is not publicly accessible and may not apply to the entire country. Studies that use state-of-the-art, modelled data, like global atlases and reanalysis, mainly focus on the global level with limited spatial resolution and/or local context.

2. *What is the technical and economic potential of variable RET in Indonesia considering spatiotemporal resource availability?*

The knowledge gaps detected in chapter 2 motivated the mapping of technical and economic RET potentials in chapters 3–6 using publicly accessible and highly resolved resource data. We mainly focus on variable RET and mapped the potentials of offshore and onshore wind, ground-mounted utility-scale solar PV, and OTEC.

In chapter 3, we determined a technical and economic offshore wind potential of up to 6,816 TWh/year and 784 TWh/year in Indonesia, respectively. These potentials arise from offshore wind turbines that are specifically designed for mild wind resources, such as Indonesia has. With LCOE as low as 13 US¢(2021)/kWh, offshore wind is not yet competitive in Indonesia against other RET, like PV and onshore wind, but could still be economically viable given high local electricity tariffs, such as in the East. Unlike for onshore wind, there are no offshore turbines for low wind speeds on the market, yet. Further research into this technology could expand the customer base of turbine manufacturers, while regions with mild wind resources would have another technology option for their energy transition.

In chapter 4, the technical and economic onshore wind potential in Indonesia range between 207–1,994 and 20–126 TWh/year, respectively. The lower limit only comprises wind farms on open, unused land, while the upper limit also includes forests, agricultural land, and conservation zones based on current regulation. The ranges arise from a newly developed flexible site selection procedure that addresses the binary, in-or-out fashion with which sites are usually mapped in literature. We found that onshore wind could cover half of projected 2030 electricity demand on all islands, with wind farms occupying between 0.1% (East Indonesia) to 17.5% (Java and Bali) of local land. However, much of the technical potential stems from sites with low wind speeds and are thus not economically feasible even with turbines designed for mild wind resources. Despite competitive local LCOEs as low as 5.8 US¢(2021)/kWh, we conclude that onshore wind is mainly interesting for Indonesia in provinces with strong wind resources, like Aceh, West Java, East Nusa Tenggara, and South Sulawesi. Elsewhere, other RET may be technically and economically preferable.

In chapter 5, we mapped the technical, socio-economic, and bankable potential of ground-mounted, utility-scale solar PV in Indonesia. For the bankable potential, we developed a methodology based on geospatial analysis, cash flow analysis, and Monte Carlo simulation to address the discrepancy in Indonesia between large technical PV potentials in literature and lacking PV investments in practice. Using average technical and economic inputs, the technical and socio-economic PV potentials are 12,216 TWh/year and 5,941 TWh/year, respectively. In bankability terms where more conservative inputs are used, the technical potential is 8,077 TWh/year, out of which 26.2 TWh/year are bankable under current conditions. Technical PV potentials are ample in Indonesia except on Java and Bali due to limited land availability. Currently, the bankable potential is mainly curbed by recent inadequate, fluctuating tariffs and policies, like import restrictions on PV panels. With a national feed-in tariff of 11.5 US¢(2021)/kWh and temporary lift of import restrictions, the bankable potential becomes 348.6 TWh/year and spreads over most of Indonesia, including Java and Bali.

In chapter 6, we present our latest OTEC study from a series of papers produced within and outside of this thesis. We determined a technical potential of 1,363 TWh/year and economic potential of 16 TWh/year without and 132 TWh/year with cost reductions for upscaling. In most cases, conservatively designed OTEC plants are the most cost-effective and produce near-constant power throughout the year even during seasonal resource fluctuations. Only in regions where these fluctuations are extreme, it is more cost-effective to downsize the systems and allow for seasonal power output fluctuations. But even then, the productivity of these plants remains high and make OTEC an interesting dispatchable RET. Earlier, we highlighted the importance of developing OTEC to full commercial scale of 100 MW_{net}, or 136 MW_{gross}. However, our global analysis revealed that small-scale plants below 10 MW_{gross} could already be economically feasible on islands with high power generation costs, like on Tonga. Hence, OTEC could be developed in its currently most relevant niche, i.e., small developing islands like in East Indonesia, and spread to larger islands, like Java, once reaching maturity.

3. *What are Indonesia's options for full power system decarbonisation considering different network configurations, cost assumptions, demand projections, as well as availability and productivity of variable RET?*

All RET potentials mapped within and outside this PhD project, as well as the potentials sourced from literature, flow into chapter 7. Using the spatially and temporally resolved energy system model Calliope, we explore full decarbonisation options for Indonesia's power sector under different transmission networks, costs, demand, and RET availability.

We find that Indonesia's options for full power system decarbonisation are diverse, with the most cost-effective ones gravitating to (1) sub-sea power links to Java, (2) high shares of PV supported by (3) pumped hydroelectric energy storage, and (4) baseload from biomass, reservoir hydropower, and geothermal.

Regarding (1) sub-sea links, 50 GW of transmission capacity, mainly between Java and Kalimantan, would enable stable levelised generation and storage costs of roughly 60 US$(2021)/MWh. These links are mainly deployed after 2040 once most of existing coal- and gas-fired power plants is retired and replaced by RET capacity. Under current projections, Java could also meet its demand locally without sub-sea links, but only with the aid of (currently) early-stage, more expensive technologies like OTEC, which drives up system costs. Then again, higher shares of OTEC could have benefits, like lower required generation and storage capacity given that OTEC's capacity factor is higher than the one of PV. If demand grows more extremely, e.g., from widespread electrification across sectors, Java's RET resources do not suffice anymore to meet demand locally. This reflects Java's limited land availability for RET deployment found in chapters 4 and 5, and consequently necessitates the import of electricity from other islands, like Kalimantan, Sumatera, and West Nusa Tenggara via Bali.

Using sub-sea links, Indonesia can tap into its massive (2) solar PV potentials, amongst others on Kalimantan. By 2050, 468 GW of solar PV would cover half of national electricity demand. To achieve this level of penetration, PV's costs need to decrease further from today's average level, e.g., via a temporary lift of import restrictions while developing Indonesia's domestic panel manufacturing capacity. The abovementioned PV capacity is accompanied by 172 GW of (3) hydroelectric energy storage, which is another key element of Indonesia's fully decarbonised power system to balance the spatial and temporal fluctuations of PV power production. Battery storage is only preferred by the model on small islands that do not possess pumped hydro potentials. Despite high shares of PV, (4) baseload generation remains important and occupies at least 77 GW and 36% of generation across all studied scenarios. In contrast, nuclear power only becomes relevant if costs decline sharply, while onshore and offshore wind power are not or only limitedly deployed even under optimistic cost assumptions, thus reinforcing our earlier findings of wind power being a local rather than a national solution for Indonesia's energy transition.

Regarding the time horizon, we find that Indonesia could achieve full power system decarbonisation by 2040, provided that decarbonisation starts now. Then, 586 $MtCO_2e$ of emissions could be avoided between 2040–2050 compared to a 2050 target, but at more ambitious and challenging installation rates for RET generation, storage, and transmission infrastructure as well as retirement rates for fossil-fuelled generation capacity. The 2040 target would also lead to higher costs from the premature retirement of coal-fired power plants.

2. Overarching discussion

In this section, we reflect upon the broader relevance of this research within and outside of Indonesia.

Our research underlined the complexity of RET potential mapping at a detail not found in the reviewed literature on Indonesia. Commonly, potentials are reported as single values and consequently imply a degree of certainty of a potential being *x*, no more, no less. However, it is not that simple. RET potentials depend, amongst others, on the land they could be built upon, on technological progress, and the regulatory framework they are embedded in.

In this dissertation, we attempted to capture these influences. In chapter 3, the technical potential of low-wind-speed offshore turbines is more than twice as large than the one of currently available turbines designed for high wind speeds, thus indicating the influence of technological innovation. In chapter 4, the technical potential of onshore wind varies by one order of magnitude depending on what land is perceived as available. In chapter 5, we revealed that risk perception also influences the potentials, i.e., whether average or more conservative technical and economic inputs are used. Across all studied technologies, the economic potentials are highly sensitive, and thus might change considerably even under minor changes in RET costs and electricity remuneration.

Against this background, RET potentials should not be seen as single values that reflect an ultimate truth, but more as a range of available resources based on the underlying assumptions. The term *available* is important as potentials only reflect the possibility, not the obligation, of RET deployment. In chapter 5, we mapped a technical PV potential of 12 PWh/year, or 9 TW. But to meet demand cost-effectively in 2050, merely 468 GW, or 5% of the technical potential, have to be deployed, according to the outcomes of the energy system modelling in chapter 7. Such findings not only render the Indonesian energy transition less daunting, as a TW-scale implementation of PV is not needed, but they also frame the otherwise isolated RET potentials better into the big picture of Indonesia's electricity system. The term *underlying assumptions* emphasises the necessity of up-to-date technical and economic information and their transparent reporting. In this research, we achieved this not only by reporting all assumptions in the published papers, but also by making our research data and code publicly accessible, which is not yet common practice in Indonesian literature (see reviews in chapters 2 and 7).

Even with all these strings attached, or perhaps *because* of these strings, the outputs of this research contribute to the scientific body of RET literature, and hopefully motivate further studies that assesses RET potentials and decarbonisation scenarios through a more critical lens and from different viewpoints. Beyond academia, our work also offers valuable insights for others stakeholders active in the Indonesian energy field. Our findings could serve as input for policymakers in the Indonesian government to draft more ambitious and more detailed energy transition plans and compose the regulatory framework supporting them. Government bodies like ESDM and the *National Energy Council (NEC)* incorporate our results, e.g., for the NEC's Indonesia Energy Outlook [359] or ESDM's renewable energy geoportal [341]. Indonesia's state-utility company PLN could use our RET potential maps as the basis for more extensive feasibility studies of RET projects at interesting sites. Moreover, PLN could further refine our maps, e.g., via validation with measured field data and upgrading to sub-hourly intervals for grid stability analyses. Developers, lenders, and investors could benefit from our work to engineer bankable business cases, and researchers could address our research recommendations in section 4.1 of this chapter.

If all the efforts above are set into motion now, Indonesia could fully decarbonise its energy system well before 2060 as currently pledged [9]. The required upscaling rates for RET may seem challenging at first, but are within global observations, at least for PV which grew by 32% p.a. globally between 2010–2021 [290]. Other countries like Vietnam show that even stronger growth is possible, where installed PV and wind capacity grew from some hundred MW in 2018 to more than 17,000 MW in 2020 due to an attractive feed-in tariff scheme. However, as generation capacity grew far stronger than grid capacity, grid congestion and increased RET curtailment therefrom pose new challenges for the country [360]. This shows the importance of a thoughtful coordination of capacity development with support schemes covering all relevant parts of the energy system, not just the generation side. After all, all parts of the system would undergo a massive transformation, amongst others from synchronous to mainly inverter-based generation and from a solely AC-based grid to a mix of AC and DC lines. The hundreds of small, rural islands would need to shift from Diesel generators to renewable microgrid solutions as it would most likely not be cost-efficient to connect all these islands via sub-sea cables. Moreover, long lead times of key components of the future power system must be taken into account, which are 7–8 years for geothermal [73], up to 13 years for overhead transmission lines, and up to 11 years for sub-sea power cables [361]. But even despite these long lead times, full decarbonisation by 2040 could be within reach. As shown in chapter 7, the main priority until 2030 is to retire the existing fossil-fuelled power capacity in Indonesia's grid, accompanied by an upscaling of solar PV, geothermal, and biomass capacity. Therefore, if the commissioning of the latter RET starts now, the 2030 systems presented in this dissertation could materialise, especially considering that the electricity generated from biomass could stem from existing coal power plants modified for biomass combustion. The first crucial steps towards coal power retirement have been made by the recently published *Comprehensive Investment and Policy Plan (CIPP)* as part of the *Just Energy Transition Partnership (JETP)* [362]. To reach full decarbonisation and projected in our work, however, these plans would also need to extend to privately owned off-grid plants, which are currently excluded from CIPP. Moreover, our results in chapter 7 suggest that a more ambitious decarbonisation by 2040 leads to only slightly higher levelised generation and storage cost compared to those of less ambitious pathways. Then again, decarbonisation by 2040 would lead to a higher share of early retirement, especially if considering the coal plants that are still under construction and are expected to go online by 2030 [9]. These new coal power plants might require significant interventions to be retired early, such as financial incentives and legal agreements between PLN and power plant owners for the termination of power purchase agreements. Note that the operational lifetime of coal power plants can be much longer in practice than the 30 years assumed [330] in this dissertation (up to 46 years as of 2024 [268]). Therefore, it must be ensured that the operation of recently and upcoming coal power capacity is not extended indefinitely. There are also non-technical changes, e.g., institutional and policy changes, required to foster the developments discussed above, which this dissertation did not focus on. Technological adoption is another challenge, as merely two AC-sub-sea links exist in Indonesia as of 2024 [9], but not yet HVDC lines.

Although this dissertation is mainly relevant to Indonesia, it also bears a global relevance. The methods that were used, further refined, and newly developed draw from global, publicly available datasets and can therefore with minor modifications be applied outside of Indonesia for any computationally feasible geographic scope. These methods contribute to the general scientific body of RET research as aspects like flexible site mapping of RET with multi land use and bankability are highly relevant regardless of region and development stage. Regarding long-term capacity planning, our research showed that island states face unique challenges, like limited land availability, and therefore require solutions tailored to the local circumstances. This applies not only to Indonesia, but also other island states like in the Caribbean Sea and Pacific Ocean.

3. Limitations

Looking back at the last three years, this dissertation is best described as a product of its time. A considerable part of it was produced during the global COVID19 pandemic. When the PhD project started in October 2020, Indonesia was still committed to long-term coal utilisation without a carbon neutrality pledge or far-reaching commitments to RET deployment. Moreover, I just left my job in Germany to work on the energy transition in Indonesia, a country to which I had strong personal ties through my wife, but not yet a professional network. All these factors influenced the outcomes of this dissertation and led to some shortcomings, which this section reflects upon.

During the first half of the PhD project, travels between The Netherlands and Indonesia were not possible or heavily restricted. Consequently, the research was built upon desk research and publicly available global datasets. This allowed for the transparent and reproducible mapping of RET potentials and modelling of Indonesia's power system. Then again, the dissertation would have benefited from a more extensive involvement and engagement with local and international stakeholders and experts in Indonesia. In chapter 2, for example, we revealed several unclarities about how official RET potentials were mapped. These aspects could have been (at least partially) clarified by reaching out to the relevant stakeholders, who I did not know at that time. Only for the solar PV study in chapter 5, my network was extensive enough for expert elucidation via online interviews, which was highly valuable for validating and discussing our inputs and results. For the energy system modelling study in chapter 7, a three-months field trip to Indonesia was planned to co-create the model and decarbonisation scenarios with local stakeholders. This trip, however, did not materialise due to COVID19 regulations preventing the application for a research visa. Then again, this limitation is alleviated by the stakeholder engagements that took place during a two-weeks field trip of the project team in October 2022 and several consortium meetings. Further stakeholder engagement and discussion results of this thesis work with relevant stakeholders in Indonesia would add value as well as further awareness and other impacts beyond the ones listed in the impact section at the end of the dissertation.

This dissertation reports on socio-economic potentials that are in line with the benchmarks used by official Indonesian bodies, but do not include all aspects of social welfare. For example, the expansion of the rural road and electricity grid infrastructure for site access might entail social benefits, but also environmental caveats, that are not accounted for in our analyses. Furthermore, the socio-economic potentials are highly sensitive to the tariff regulations that were in place during the time of the studies. During this research, the tariffs based on local system generation costs were updated twice and replaced by a new scheme based on technology generation costs in 2022. We addressed the impact of tariff changes on the socio-economic potential via sensitivity analyses, amongst others, to maintain the results' relevance in case of regulatory changes. Nonetheless, the risk of misinterpretation remains.

Moreover, our research did not directly incorporate the sub-provincial differences in socio-economic development between Indonesia's islands except for electricity tariffs. This is most evident for the economic RET potentials which are mainly situated in East Indonesia. We do discuss these potentials critically against the low local electricity demand there, as well as the impact of limited road and grid infrastructure. Other location-specific elements, however, did not flow into the economic and financial analyses, e.g., political stability in areas like Papua and electricity consumption patterns of rural communities with limited electricity access. In chapter 7, we showed that the shape of the demand profile has a limited influence on the cost-optimal system configuration. However, we did not corroborate this finding against substantially different profiles, e.g., in off-grid systems. To address the points above, we would have needed thorough, publicly available data at the sub-provincial level, e.g., for off-grid electricity demand or risk premia for politically less stable areas. To our knowledge, though, such datasets do not exist yet for Indonesia.

In 2022, electricity only accounted for 15% of Indonesia's final energy consumption, with oil and coal having the highest shares with 40% and 25%, respectively [3]. Oil is mainly used in the transportation sector, while coal is not only used for electricity, but also for heat production in energy-intensive manufacturing industries. Therefore, this dissertation's focus on the electricity sector could be considered as too narrow from a whole energy system perspective. However, with further electrification via appliances like electric vehicles and heat pumps, the electricity sector will play an increasingly important role in Indonesia's energy system. We acknowledged this by using different demand projections that reflect various levels of future electrification and our results indicate that Indonesia's renewable energy resources could allow for a large-scale electrification (assuming that the resources are distributed to locations where they are needed). However, our research did not answer what levels of electrification are most cost-effective and which technologies should be deployed. For example, we assume in chapter 7 that all biomass waste resources are used for power generation. However, could it be more cost-effective to synthesize biofuels with (some of) the biomass for transport purposes? Or are e-fuels from electrolysis using solar electricity more cost-effective than biofuels? Even for the power system there are aspects that our research did not address, e.g., how smart grids and demand side flexibility could reduce the need for energy storage and island links. Moreover, we did not include the impact of climate change in our RET resource assessments, e.g., the impact of ocean warming on OTEC [300]. Although this dissertation paved the way for tackling the points above, the answers for Indonesia's energy transition remain incomplete as long as they are not framed with the entire energy system.

For this dissertation, we deployed a paper-based approach with a consecutive publication strategy, meaning that each chapter was immediately submitted for publication in a peer-reviewed journal once completed. This decision had benefits and drawbacks over a bulk publication strategy, where all outcomes are produced first and only submitted for publication at the end of the PhD project. The biggest benefit of our strategy was that the published research drew the attention of fellow researchers, official bodies, non-government organisations, and investors and thus made an immediate and tangible impact at an early stage of the PhD project. Moreover, the peer reviews further improved the quality of the individual studies and thus the dissertation as a whole. In chapters 3 to 5, we mapped RET potentials with a general GIS-based workflow and added technology-specific analyses, e.g., on bankability, to create a more comprehensive methodology with greater added value for Indonesian and global RET research. However, these additional analyses introduced methodological inconsistency between chapters 3 to 5. With a bulk publication strategy, each chapter could have been updated iteratively, which would have made the dissertation methodologically more consistent, but also more time-consuming. Another drawback are the spikes in workload as there were times were several paper submissions needed to be handled at the same time under hard deadlines.

In our view, these limitations did not affect the overall quality and usefulness of the research outcomes and provide several channels for follow-up research, which are discussed in the next section.

4. Recommendations

4.1. Research recommendations

Mapping of further RET across Indonesia

Future research could map the technical and economic potential of RET that were not addressed in this dissertation, especially biomass, reservoir hydro, and geothermal. In chapter 7, we showed that these RET play an important role for Indonesia's fully decarbonised power system, and that their deployment is mainly limited by resource availability. Besides their cost-effectiveness, these dispatchable generations contribute to the balancing of the electricity grid and enable the large-scale penetration of variable renewables. Therefore, we see great merit in sharpening the technical and economic potentials of these RET, especially considering that existing estimations mainly originate from official sources with the shortcomings discussed in chapter 2. Then, important questions specific to these technologies could be addressed, e.g., how to source the necessary biomass for electricity generation, and what is the environmental impact of large-scale geothermal and reservoir hydro deployment.

Some RET were omitted in this dissertation, like wave and tidal energy, rooftop PV, and concentrated solar power. As discussed in Box IV in chapter 7, we estimate that their inclusion would not have substantially changed the cost-effective power system configurations under the used assumptions. Nevertheless, there might still be value in mapping these RET across Indonesia. There could be resource hotspots relevant to the local, sub-provincial energy transition, as seen for onshore wind. Moreover, mapping rooftop PV potentials could help gauging the extent to which homeowners, amongst others, could actively participate in Indonesia's energy transition. For Java, it could be beneficial to have further options at hand to meet demand locally, e.g., from wave power, e.g., if a too strong dependency on electricity imports from other islands is politically not desired. Addressing these aspects might increase the social and political acceptance of the energy transition, which are not considered by the energy system model that purely acts on costs.

Enhancement of socio-economic potentials, especially for remote and rural regions

Some Indonesian officials consider coal as the driver of socio-economic development [4]. Future research could focus on how Indonesia's development can be maintained by renewables after fossil fuels are phased out. One way could be to capture the socio-economic benefits and costs of RET on Indonesia's social welfare beyond electricity production, e.g., via a cost-benefit analysis as done by Pojadas & Abundo [278] for The Philippines and the Asian Development Bank [284] for evaluating the economic potential of public infrastructure projects. Such analyses are especially relevant for remote and rural areas where a continuous and reliable access to electricity has not yet been established. For such regions, future work should not only address the socio-economic potential of individual RET, but system solutions like microgrids. There are many synergies that could be lifted between our research and other recent projects that focussed on Indonesia's rural areas, like the ANRGI project [363] conducted by University Twente. For example, the hourly generation profiles created here could be upgraded to a second-to-minute level and used to design microgrid configurations and test their stability considering the variability of RET production. These technical insights could then be coupled with stakeholder engagement to incorporate the local values and beliefs into the system designs. Moreover, the social dimension of Indonesia's energy transition could be further explored via the combination of quantitative and qualitative research. For example, the quantitative results from energy system modelling could be further assessed through the lens of energy justice, governance, employment impacts, and other relevant topics. This would add another dimension to the modelling results and provide further insights on the accelerators and obstructors of Indonesia's energy transition and how they could be affected by policies, regulations, as well as local beliefs and values.

Expand on energy system modelling research

Chapter 7 already offers many options for Indonesia's full power system decarbonisation. Nonetheless, further system configurations exist that have not yet been touched upon by our model, including systems with carbon capture and storage, sector-coupling, and an interconnected electricity grid spanning across Southeast Asia. Future work could also explore near-optimal, but still economically feasible, solutions via *Modelling to Generate Alternatives*, e.g., with Calliope's built-in function called SPORES [335]. Furthermore, the system configurations generated here could be refined with the feedback from Indonesian stakeholders, like capacity planners and government officials, to frame them better into the Indonesian real-life context. Our model could also be extended to the sub-provincial level to capture the local RET hotspots that were distorted by the spatial aggregation of generation profiles to the provincial level in chapter 7. Grid stability analyses are not only relevant for rural microgrids, but also for the large transmission grids across Indonesia. Hence, future research could build upon earlier works for Indonesia, e.g., on frequency stability [364–367], and incorporate the findings of this dissertation to ensure the safe integration of large shares of RET into Indonesia's current and future electricity grid. Furthermore, we recommend the investigation of non-technical changes needed to foster the decarbonisation pathways reported and discussed here, e.g., in terms of required institutional and regulatory changes.

4.2. Policy and industry recommendations

Re-evaluate the current carbon neutrality pledge towards 2050 or earlier

Indonesia's pledge to become carbon neutral by 2060 or earlier [8] was a big step forward from previous fossil-fuel-heavy long-term energy plans, like RUEN [5]. Nonetheless, our research showed that Indonesia could fully decarbonise its power system much earlier, provided that the process starts now (chapter 7). As climate change mitigation cannot wait, we strongly recommend Indonesia's policy makers to re-evaluate the existing carbon neutrality pledge and to consider a more ambitious target year of 2050 or earlier. The pledge should target the phase out of *all* fossil-fuel-based generators, including privately owned off-grid coal power plants that are not addressed in the *Comprehensive Investment and Policy Plan (CIPP)* of JETP [362]. Current medium-term plans like PLN's 10-year business plan RUPTL already lay out investment and development plans for local generation, storage, transmission, and distribution infrastructure based on demand-side projections. An updated pledge could be based on a similar level of detail, just spread out over a longer time horizon until 2050 and beyond.

Establish a safe environment for the and investment in all parts of the electricity system

The expert elucidation done in chapter 5 revealed that regulatory uncertainty is one of the biggest obstacles renewables faces in Indonesia. In recent years, RET support schemes changed several times, from feed-in tariffs to individually negotiated tariffs capped by ceiling prices, which were initially based on the generation costs of the entire local power system and now on the generation costs of the RET itself. We see the most recent scheme as a step in the right direction as it sets more adequate technology- and location-specific ceiling tariffs throughout a plant's lifetime and thus improves the negotiation position of RET developers. We recommend further measures to refine the current scheme and foster a safe environment for RET development and investment in Indonesia's entire electricity system, including power transmission and distribution. Processes that involve PLN should be streamlined to reduce administration costs and shorten development times. This could be achieved by using standardised contracts for the tendering of RET projects as well as for power purchase agreements between PLN and independent power producers, as well as adequate tariff or royalty schemes for transmission and distribution system operators. Furthermore, PLN could develop a binding RET project pipeline so that projects do not have to go through internal approval cycles. Such a pipeline might also be helpful for RET with long lead times, e.g., reservoir hydro and sub-sea power lines, as a binding commitment might motivate the necessary first steps in their development like feasibility studies. If the project pipeline stretches over a longer time-horizon, it might also be aligned with the commercialisation of early development RET, such as low-wind-speed offshore wind power and OTEC.

The reduction of financing costs is another key element for fostering investments in capital-intensive technologies like solar PV (see chapter 5) and transmission lines. While the measures above might already drive down costs of capital due to lower implementation and remuneration uncertainty, we further recommend capacity building in Indonesia's banking sector and the establishment of a global renewable energy fund to enable low-interest finance from both domestic and international lenders and investors.

Develop a solar power strategy

This research shows that, just like in most other countries in the world, solar PV is the most important piece of Indonesia's energy transition puzzle. Besides the recommendations provided in chapter 5, like temporary lift of PV panel import restrictions and capacity building in the banking sector, we further recommend the development of a solar power strategy to promote PV's widespread and socio-economically conducive development, covering all parts of the country and relevant technologies, namely ground-mounted, floating, and rooftop PV. The strategy could involve a timeline for capacity installation until a certain year, the development of national knowledge hubs and value chains (including manufacturing and maintenance facilities), and the conception of viable business cases. For example, home and business owners could rent a rooftop PV system owned, built, and operated by PLN. This could be a win-win as PLN would still generate revenue from rooftop PV systems via a monthly rent, while rooftop owners would benefit from electricity cost savings without having to pay the system's high upfront costs. Such business cases would address two major barriers of solar PV in Indonesia, namely high upfront costs for rooftop owners and forfeited revenues for PLN [368].

Appendices

A. Revisions made to the RET review paper in chapter 2

The following revisions pertain to the published paper by Langer, J., Quist, J., Blok, K. Review of Renewable Energy Potentials in Indonesia and Their Contribution to a 100% Renewable Electricity System. Energies 2021, 14, 7033. https://doi.org/10.3390/en14217033, in the following referred to as *the paper*.

In the paper, we distinguish between theoretical, technical, practical and economic potentials. Although terms like practical or realistic potential are used by Indonesia's Ministry for Energy and Mineral Resources [65] and another study [110], it is more common to include practical constraints in the technical potential, which we also ended up doing in this dissertation. For consistency and alignment with general literature, this chapter only distinguishes between theoretical, technical, and economic potentials, thus omitting the term practical potential used in the paper.

We compared the RET potentials to current and future demand in terms of consumed electricity. However, this omits losses from power transmission and distribution. Moreover, we found a referencing mistake as the 2050 demand of 2,046 TWh could not be traced in the given references ([5,19] in the paper). In this chapter, we compare the potentials to the demand in terms of required generation, which with 284 and 2,190 TWh deviate by 10% and 7% from the values used in the paper, respectively.

Moreover, we mistakenly reported ESDM's geothermal potentials in terms of thermal capacity instead of electricity capacity in accordance to the methodology by Indonesia's national body of standardisation [369], which we corrected in chapter 2.

We contacted the publisher with the request for a corrigendum addressing the points above, which however remained unanswered to this day.

B. Currency conversion (chapters 3 to 7)

Year	US$(year) to US$(2021)	EUR(year) to US$(year)	Rupiah(year) to US$(year)	AUS$(year) to US$(year)	Rupee(year) to US$(year)
2021	1	1.2	-	-	-
2020	1.01	1.14	14,572	-	-
2019	1.04	1.12	-	-	-
2018	1.06	1.18	14,246	-	-
2017	1.08	1.13	13,383	0.79	-
2016	1.10	1.11	-	-	-
2015	1.12	1.11	-	-	-
2014	1.12	1.33	-	-	-
2013	1.14	1.33	-	-	-
2012	1.15	1.29	-	-	-
2011	1.19	1.39	-	-	-
2010	1.21	1.33	-	-	-
2009	1.24	1.39	-	-	-
2008	1.24	-	-	-	-
2007	1.29	-	-	-	-
2006	1.32	-	-	-	0.022
2005	1.37	-	-	-	-
2004	1.41	-	-	-	-
2003	1.44	-	-	-	-
2002	1.48	-	-	-	-

Conversion rates to US$(2021). We use the conversion rates from [237] for US$(year) to US$(2021), [236] for EUR to US$, [198] for Indonesian Rupiah to US$, [198,370] for AUS$ to US$, and [371] for Rupee to US$.

C. Onshore and offshore wind farm cost model (chapters 3 and 4)

General CAPEX components

Component	Cost function based on	Currency-adjusted cost function in US$(2021)	Remark
Blades	Rotor radius *D/2*	$\frac{\left(\left(0.4019*\left(\frac{D}{2}\right)^{3}-955.24\right)+2.7445*\left(\frac{D}{2}\right)^{2.5025}\right)*3*1.48}{1-0.28}$	-
Hub	Rotor diameter *D*, mass of a blade m_{blade} and hub m_{hub} $m_{blade} = \left(0.1452 * \left(\frac{D}{2}\right)^{2.9158}\right)$ $m_{hub} = 0.954 * m_{blade} + 5{,}680.3$	$m_{hub} * 4.25 * 1.48$	-
Pitch	Rotor diameter *D*	$2.28 * (0.2106 * D^{2.6578}) * 1.48$	-
Cone	Rotor diameter D and mass of cone m_{cone} $m_{cone} = 18.5 * D - 520.5$	$m_{cone} * 5.57 * 1.48$	-
Low-Speed Shaft	Rotor diameter *D*	$0.1 * D^{2.887} * 1.48$	Original factor 0.01 does not match with costs in example calculation in [187], hence adjustment to 0.1.
Bearing	Rotor diameter *D* and mass of bearing $m_{bearing}$ $m_{bearing} = \left(D * \frac{8}{600} - 0.033\right) * 0.0092 * D^{2.5}$	$2 * m_{bearing} * 17.6 * 1.48$	-
Gearbox	Type of drivetrain and rated power P_{rated}	**Direct drive:** 0 **Three-stage planetary/ helical:** $16.45 * P_{rated}^{1.249} * 1.48$	-
Generator	Type of drivetrain and rated power P_{rated}	**Direct drive:** $P_{rated} * 219.33 * 1.48$ **Three-stage planetary/ helical:** $P_{rated} * 65 * 1.48$	-

Turbine cost model used in this dissertation. For the wind farm cost, the total turbine cost are multiplied with the number of turbines of the wind farm. For currency adjustment, the conversion rates in Appendix B are used. If not stated otherwise, the cost functions are based on [187].

(continued)

Component	Cost function based on	Currency-adjusted cost function in US$(2021)	Remark
Mainframe	Type of drivetrain and rotor diameter *D*	**Direct drive:** $1.96 * 627.28 * D^{0.85} * 1.48$ **Three-stage planetary/ helical:** $1.96 * 9.489 * D^{1.953} * 1.48$	Factor 1.96 added due to discrepancies with the example calculation in [187].
Brake	Rated power P_{rated}	$(1.9894 * P_{rated} - 0.1141) * 1.48$	-
Variable-Speed Electronics	Rated power P_{rated}	$79 * P_{rated} * 1.48$	-
Yaw	Rotor diameter *D*	$2 * (0.0339 * D^{2.964}) * 1.48$	-
Platform	Type of drivetrain, mass of mainframe m_{main} and rotor diameter *D* **Direct drive:** $m_{main} = 1.96 * 1.228 * D^{1.953}$ **Three-stage planetary/ helical:** $m_{main} = 1.96 * 2.233 * D^{1.953}$ $m_{platform} = 0.125 * m_{main}$	$8.7 * m_{platform} * 1.48$	Factor 1.96 added due to discrepancies with the example calculation in [187].
Electronic Connections	Rated power P_{rated}	$40 * P_{rated} * 1.48$	-
Hydraulics Cooling	Rated power P_{rated}	$12 * P_{rated} * 1.48$	-
Nacelle	Rated power P_{rated}	$11.537 * P_{rated} + 3{,}849.7 * 1.48$	-
Control, Safety & Monitoring	Constant	$55{,}550 * 1.48$	-
Tower	Mass of tower m_{tower}, rotor diameter *D* and hub height *h* $m_{tower} = 0.3973 * \frac{\pi}{4} * D^2 * h - 1{,}414$	$1.5 * m_{tower} * 1.48$	-
Marinisation	Turbine and tower cost $C_{turb\&tower}$	$0.135 * C_{turb\&tower}$	Only for offshore wind.
Turbine and Tower Cost	-	Sum of all components above multiplied with correction factor *X:* **Onshore:** *X = 0.593* **Offshore:** *X = 0.81*	Correction factor *X* based on cost developments reported in [174] in US$(2019).

(continued)

Onshore wind CAPEX components

Component	Cost function based on	Currency-adjusted cost function in US$(2021)	Remark
Foundation	Rated power P_{rated}	$59 * P_{rated} * 1.04$	-
Site Access & Staging	Rated power P_{rated}	$44 * P_{rated} * 1.04$	-
Assembly & Installation	Rated power P_{rated}	$44 * P_{rated} * 1.04$	-
Development, Engineering, & Management	Rated power P_{rated}	$34 * P_{rated} * 1.04$	-
Construction Financing & Contingency Fund	Rated power P_{rated}	$120 * P_{rated} * 1.04$	-

Offshore wind CAPEX components

Component	Cost function based on	Currency-adjusted cost function in US$(2021)	Remark
Offshore Structure	Water depth z and rated power P_{rated}	**If $z \le 25$ m → Monopile** $(0.201 * z^2 + 0.613 * z + 411.464) * P_{rated} * 1.11 * 1.10$ **If 25 m < $z \le 55$ m → Jacket** $(0.114 * z^2 - 2.270 * z + 531.738) * P_{rated} * 1.11 * 1.10$ **If 55 m < z ≤ 1,000 m → Floating** $(0.774 * z + 680.651) * P_{rated} * 1.11 * 1.10$	Only for offshore wind. Cost function based on [17], because the cost function in [187] was not depth-dependent, which necessitated the use of a modified cost function as shown to the left.
Power Transmission	Distance to onshore connection l and rated power P_{rated}	**If $l \le 50$ km → HVAC** $(8.5 * l + 56.8) * P_{rated} * 1.11 * 1.10$ **If l > 50 km → HVDC** $(2.2 * l + 387.8) * P_{rated} * 1.11 * 1.10$	Only for offshore wind. Cost function based on [17], because the cost function in [187] was not distance-dependent, which necessitated the use of a modified cost function as shown to the left.
Permits & Engineering	Rated power P_{rated}	**Fixed-bottom turbines:** $208 * P_{rated} * 1.04$ **Floating turbines:** $250 * P_{rated} * 1.04$	Only for offshore wind. Modified function based on cost developments reported in [174] in US$(2019).
Personnel Equipment	Constant	$60{,}000 * 1.44$	Only for offshore wind.
Scour Protection	Rated power P_{rated}	$55 * P_{rated} * 1.44$	Only for offshore wind.

(continued)

Port Staging, Transport & Installation	Constant	**Fixed-bottom turbines:** $2{,}688{,}000 * 1.04$ **Floating turbines:** $1{,}212{,}000 * 1.04$	Only for offshore wind. Summarises the costs of port staging, transport, installation in [187]. The costs apply on a per-turbine basis to remove the bias for the rated power in [187]. The used values are based on the cost reported in [174].
Balance of System Cost	-	Sum of costs for structure, transmission, permits & engineering, personnel equipment, scour protection, and staging, transport & installation	
Soft Costs	Rated power P_{rated}	**Fixed-bottom turbines:** $733 * P_{rated} * 1.04$ **Floating turbines:** $878 * P_{rated} * 1.04$	Modified function based on cost developments reported in US$(2019). Includes commissioning, decommissioning, contingency, construction finance, and insurance[174].

OPEX components

Component	Cost function based on	Currency-adjusted cost function in US$(2021)	Remark
Variable OPEX	Annual electricity production E_a (excluding efficiencies and availability factor)	$(0.02 + 0.00108) * 1.48 * E_a$	Summarises costs for operation & maintenance and bottom lease.
Fixed OPEX	Rated power P_{rated}	$17 * 1.48 * P_{rated}$	-
Total OPEX	-	$(OPEX_{var} + OPEX_{fixed}) * X$ **Onshore turbines:** *X = 0.71* **Fixed-bottom turbines:** *X = 0.8* **Floating turbines:** *X = 0.84*	Correction factor *X* based on cost developments reported in [174] in US$(2019). For both variable and fixed OPEX, we do not differentiate between different drivetrains, which in practice might affect OPEX.

D. Wind turbine placement in Indonesia (chapter 4)

Screenshot of a part of the Jeneponto wind farm in Indonesia from google maps. The distances between turbines and to the closest house were measured with the distance measurement tool of google maps [221].

E. Properties of studied onshore wind turbines (chapter 4)

Turbine-specific assumptions (all information from [153])							
Turbine name	Wind class	Rated power [kW]	Cut-in/ rated/ cut-out wind speed [m/s]	Rotor diameter [m]	Ratio of rated power to swept area [W/m^2]	Capacity density [MW/km^2]	Direct drive?
UP86	IIIb	1,500	2.5/ 10.5/ 25	86	258	4.1	no
GW82/1500	IIIa	1,500	3/ 11/ 25	82.3	282	4.4	no
LWT90/1500	IIIa	1,500	3/ 11.5/ 25	90.3	234	3.7	no
SG1700.100	SA6.5	1,700	3/ 10/ 20	100	216	3.4	no
WD103-2000	Ia	2,000	2.5/ 10/ 20	103	240	3.8	no
H93-2000	IIIa	2,000	2.5/ 11/ 25	92.8	296	4.6	no
TZ2000/116	-	2,000	3/ 9/ 25	116	189	3.0	no
WT2000df/113	IIIa	2,000	3/ 9.5/ 20	113	199	3.1	no
XE93-2000	IIb	2,000	3/ 10.5/ 25	93.4	292	4.6	yes
HJWT2000/87	IIa	2,000	3/ 11/ 25	87	336	5.3	no
SG2.1-114	IIa/IIIa/S	2,100	1.5/ 9/ 25	114	206	3.3	no
AGW 110/2.1	S	2,100	2.5/ 11/ 20	110	221	3.5	yes
U120	S/IIIB	2,300	3/ 9.8/ 22	120	203	3.2	no
G114/2500*	IIa	2,500	2.5/ 11/ 24	114	245	4.1	no
WD103-2500	IIa	2,500	2.5/ 11/ 25	103	300	4.7	no
TZ2500/122	III	2,500	3/ 9.3/ 25	122	214	3.4	no
SG2500.131 DD	SA 6.5	2,500	3/ 10/ 20	131	185	2.9	yes
Vensys 121	IIIa	2,500	3/ 11/ 22	121	217	3.4	yes
SG2700.116 DD	IIIa	2,700	3/ 10.5/ 24	116	255	4.0	yes
WT3000df/140	IIIa	3,000	3/ 9.5/ 20	140	195	3.1	no
GW140/3400	IIIa	3,400	2/ 10.5/ 20	140	221	3.5	yes
V136/3450	IIa	3,450	2.5/ 11/ 22	136	237	3.7	no
Vensys 136	IIIa	3,500	2.5/ 11.5/ 22	136	241	3.8	yes
SWT-3.6-130*	II	3,600	2.5/ 13/ 25	130	271	4.3	yes
XD140-4000	II	4,000	3/ 10.5/ 25	140	260	4.1	yes
V150/4200	IIIb	4,200	3/ 9.9/ 22.5	150	238	3.7	no
AGW147/4.2	S	4,200	3/ 11/ 20	147	247	3.9	yes
U151	IIIa	4,300	3/ 10.2/ 25	151	240	3.8	no

Properties of studied onshore wind turbines. The capacity density is based on a turbine spacing of 5D×10D, with D being the rotor diameter. Turbines marked with an asterisk* are currently deployed in Indonesia and are included for validation purposes.

F. Search queries and literature sampling methods in chapter 5

Studies on utility-scale solar PV's economic potential using geospatial analysis

TITLE-ABS-KEY ("solar energy" OR "solar power" OR " solar photovoltaics" OR "solar PV" OR "photovoltaics" AND (evaluat* OR analy* OR poten* OR plan* OR simul* OR optimi* OR model*) AND ("technical" OR economic* OR techno-economic) AND ("GIS" OR "mapping")) AND (LIMIT-TO (PUBYEAR , 2022) OR LIMIT-TO (PUBYEAR , 2021) OR LIMIT-TO (PUBYEAR , 2020) OR LIMIT-TO (PUBYEAR , 2019) OR LIMIT-TO (PUBYEAR , 2018) OR LIMIT-TO (PUBYEAR , 2017) OR LIMIT-TO (PUBYEAR , 2016) OR LIMIT-TO (PUBYEAR , 2015) OR LIMIT-TO (PUBYEAR , 2014) OR LIMIT-TO (PUBYEAR , 2013) OR LIMIT-TO (PUBYEAR , 2012)) AND (LIMIT-TO (PUBSTAGE , "final")) AND (LIMIT-TO (DOCTYPE , "ar")) AND (LIMIT-TO (LANGUAGE , "English")) AND (LIMIT-TO (SRCTYPE , "j"))

Studies on solar energy project finance

TITLE-ABS-KEY(Solar and "project finance") AND (LIMIT-TO (DOCTYPE,"ar"))

Sampling methodology

We provide an overview of the recent scientific literature on (A) economic geospatial analyses and (B) project finance of solar PV, thus omitting other solar energy technologies like concentrated solar power. We consider recent, English, peer-reviewed journal articles from 2012–2022 in Scopus using the search queries above. Our total sample comprises 264 papers for (A), and 14 papers for (B) (April 2022). Irrelevant papers are removed in a subsequent title, abstract, and full-text scan, resulting in 8 reviewed papers for (A), and six for (B). We reviewed two further papers [265,266] that apply Monte Carlo analysis without mentioning "project finance" due to relevance of subject matter.

G. Project finance glossary (chapter 5)

Term	Meaning (if abbreviation)	Additional explanation
General terms and inputs of debt sizing and cash flow analysis		
Amortisation	-	Accounting method: (1) to distribute the costs of an intangible asset (e.g. patent) over its useful lifetime or (2) to reduce or payoff the book value of debt/loan with regular payments over a certain period of time.
CFADS	Cash flow available for debt service	-
CoD	Cost of debt	The interest rate on a loan from a lending institution like a bank.
CoE	Cost of equity	The expected rate of return on the investment by sponsors.
Debt-to-capital ratio	-	The ratio between debt and total capital expenses.
Depreciation	-	Accounting method to distribute the costs of a tangible asset (e.g. machinery) over its useful lifetime.
DSCR	Debt service coverage ratio	Ratio between cash flow available for debt service and the mandatory debt service (i.e. loan and principal).
EBIT	Earnings before interest and taxes	EBITDA minus depreciation and amortisation.
EBITDA	Earnings before interest, taxes, depreciation, and amortisation	Revenue minus operating expenses.
EBT	Earnings before taxes	EBIT minus interest.
FCFE	Free cash flow to equity	Cash flow received by sponsors after subtracting all expenses (incl. tax and principal) from the revenue.
Interest	-	The charge for borrowing money from a lending institution like a bank.
Lender	-	Stakeholders who provide debt to the project, like banks or other lending institutions. Also called 'syndicate'.
Loan repayment period	-	The period within which the loan must be fully repaid.
Principal	-	The amount of borrowed money to be paid back to a lending institution like a bank.
Revenue	-	The income received from selling the produced electricity at the given tariff excluding any expenses.
Sponsor	-	Stakeholders who provide equity to the project, like investors.
WACC	Weighted average cost of capital	The weighted sum of cost of debt and equity.
Outputs of cash flow analysis		
IRR	Internal rate of return	Rate of return required to cover all discounted cost and to break even at the end of the plant's useful lifetime (tariff given)
LCOE	Levelized cost of electricity	Tariff necessary to cover all discounted costs and to break even at the end of the plant's useful lifetime (discount rate given)
NPV	Net present value	The total present value of future cash flows (both costs and revenues).

H. Data and models used for the solar PV plant modelling (chapter 5)

Data/ Task	Used datasets/ model	Ref
Datasets		
Surface pressure [Pa] Ambient temperature 2m above ground [K] Dew point temperature 2m above ground [K] Surface solar radiation downwards [J/m^2] u-component of wind at 10m height [m/s] v-component of wind at 10m height [m/s]	Hourly ERA5 data from 2001–2020	[46]
Specific power production for bias correction [kWh/kW$_p$]	Global Solar Atlas	[44]
PVLIB functions (all from [271]**)**		
Diffuse irradiation	Isotropic sky model (pvl_isotropicsky)	
Direct normal irradiation	DISC model (pvl_disc)	
PV module temperature	SAPM cell temperature model (pvl_sapmcelltemp, using default coefficients for glass/cell/glass modules)	
Spectral loss	pvl_FSspeccorr	
Angle of incidence loss	ASHRAE model (pvl_iam_ashrae)	
I-V curve	pvl_calcparams_CEC	
DC power production	Single-diode model (pvl_singlediode)	

I. Tariff ranges used in chapter 5

Region	Tariff range [US¢(2021)/kWh] Min	Max	Region	Tariff range [US¢(2021)/kWh] Min	Max
Aceh	7.98	10.75	Manokwari	9.48	13.53
Ambon	14.27	18.95	Merauke	13.89	16.33
Anambas	11.80	18.31	Nabire	12.48	19.14
Bacan	12.89	16.84	Natuna	11.66	14.09
Bali	5.37	6.24	Nias	16.59	19.14
Bangka	11.87	16.88	Nusa Ceningan	11.45	17.39
Banten	5.37	6.24	Nusa Lembongan	11.45	17.39
Bau-Bau	9.29	14.92	Nusa Penida	11.45	17.39
Bawean	11.62	19.14	Palu	6.45	7.73
Belitung	11.33	12.91	Poso	6.45	7.73
Bengkulu	6.15	6.68	Pulau Enggano	16.59	19.14
Biak	11.60	18.15	Pulau Pagai	13.72	19.14
Bima	10.89	17.21	Pulau Panjang	16.59	19.14
Bintan	10.84	14.05	Pulau Siberut	13.72	19.14
Bintuni	11.41	18.31	Pulau Simeulue	10.96	16.68
Buru	13.91	19.01	Pulau Sipura	13.72	19.14
Daruba	15.38	19.14	Pulau Weh	11.81	14.50
DKI Jakarta	5.37	6.24	Raja Ampat	16.59	19.14
Dobo	13.11	19.14	Riau	8.13	10.41
Fak-Fak	12.15	18.31	Sanana	12.47	15.65
Flores Bagian Barat	9.67	16.22	Saparua	14.81	18.85
Flores Bagian Timur	10.98	19.09	Sarmi	12.80	15.04
Gili Ketapang	12.64	19.14	Saumlaki	13.61	15.32
Gorontalo	9.11	12.07	Selayar	13.97	15.39
Halmahera	13.70	18.66	Seram	12.83	18.70
Jailolo	13.70	18.66	Serui	13.31	13.80
Jambi	6.15	6.68	Sofifi	13.70	18.66
Java Barat	5.37	6.24	Sorong	8.82	11.99
Java Tengah	5.37	6.24	Sulawesi Barat	5.67	7.40
Java Timur	5.40	6.25	Sulawesi Selatan	5.67	7.40
Jayapura	10.64	19.14	Sumatera Barat	5.89	6.66
Kaimana	13.16	19.14	Sumatera Selatan	6.15	6.68
Kalimantan Barat	9.10	11.57	Sumatera Utara	7.38	9.13
Kalimantan Selatan	7.36	10.58	Sumba	12.70	18.67
Kalimantan Tengah	7.36	10.58	Sumbawa	10.89	17.21
Kalimantan Timur	7.82	10.14	Tahuna	12.96	18.44
Kalimantan Utara	7.82	10.14	Tambora	10.89	17.21
Karimun Java	16.59	19.14	Tanah Merah	13.10	19.14
Kendari	6.27	14.61	Tanjung Balai Karimun	9.14	13.29
Kepulauan Seribu	5.02	7.33	Teminabuan	12.78	17.52
Kotamobagu	9.11	12.07	Ternate	13.01	18.31
Lampung	5.89	6.54	Tidore	13.01	18.31
Lombok	10.14	12.87	Timika	11.60	16.33
Luwuk	9.84	15.13	Timor	12.23	16.56
Maba	13.70	18.66	Tobelo	13.70	18.66
Madura	12.14	19.14	Toli-Toli	11.33	18.23
Malifut	13.70	18.66	Tual	7.59	19.14
Manado	9.11	12.07			

Tariff ranges used per region (in Indonesian) based on current regulation in Indonesia. The tariffs are based on each region's basic generation cost (BPP), adjusted for US¢/(2021), and then multiplied by 85% to reflect the maximally receivable tariff.

J. List of contacted experts and interview questions (chapter 5)

Stakeholder group	Expert	Description	Interaction
Government	Government #6	Staff of Indonesian Financial Services Authority (OJK Indonesia).	Provided relevant document [287].
International organisation	IO representative #1	Senior Energy Specialist at Asian Development Bank (ADB).	Provided relevant documents [284,372].
Private sector	Private sector #1	Senior Energy Consultant at international consulting firm.	1-hour semi-structured conversation.
Private sector	Private sector #2	Senior Solar PV Consultant at Indonesian consulting firm.	1-hour semi-structured conversation.
Private sector	Private sector #3	Consultant at international consulting firm & former Indonesian PV engineer.	1-hour semi-structured conversation.
Private sector	Private sector #4	Founder of Indonesian renewable energy start-up.	1-hour semi-structured conversation.
Private sector	Private sector #5	Lead engineer at international energy company.	1-hour semi-structured conversation.
State-owned enterprise	SOE #1	Manager at PLN.	1-hour semi-structured conversation.
State-owned enterprise	SOE #2	Renewable energy engineer at PLN.	1-hour semi-structured conversation.

Approval for the semi-structured interviews was requested from and given by the Human Research Ethics Committee (HREC) of TU Delft. Consent was asked and given by all interviewees. The interview questions are listed below:

I. Please tell a bit about yourself and your involvement in the Indonesian energy transition?
II. What developments did you see in the field in the last years?
III. What investment costs did you recently see for large-scale solar PV systems in Indonesia? (*Preferably in USD/kWp)*
IV. What operation & maintenance (O&M) costs did you recently see for solar PV systems in Indonesia? (P*referably in USD/kWp/year)*
V. In your view, how much does the local content rule affect the economic potential of solar PV in Indonesia?
VI. What is the impact of proximity to the electricity grid and roads on solar PV's economic feasibility and what are the costs of grid connection and road construction per [km]?
VII. How are solar PV projects usually financed in Indonesia? Please make an estimation for the following parameters:
   - Corporate or project finance?
   - Debt-to-equity ratio
   - (weighted) cost of capital
   - Cost of debt and equity
VIII. Which economic metrics (LCOE, NPV, etc.) are the most important for you to assess solar PV's economic feasibility? What thresholds do you use for these metrics?
IX. Have you ever experienced situations where stakeholders had different views on the economic feasibility of a project?
X. What would need to happen in your view to promote the development of solar PV in Indonesia and to solve current issues and challenges?
XI. Is there anything you would like to add? Can you recommend people we could contact for further interviews?
XII. Would you be willing and available for a follow-up interview on stakeholder-inclusive energy transition scenarios?

K. Project finance model (chapter 5)

Symbols and Indices

Symbol	Meaning	Unit (if applicable)
BPP	Biaya pokok penyediaan (basic costs of electricity provision)	US¢(2021)/ kWh
CAPEX	Capital expenses	US$(2021)
CoD	Cost of debt	%
CoE	Cost of equity	%
CRF	Capital recovery factor	-
d	Debt-to-capital ratio	%
DSCR	Debt service coverage ratio	-
e	Escalation rate (for system degradation and inflation)	%
E	Electricity production	kWh/year
EBIT	Earnings before interest, and taxes	US$(2021)
EBITDA	Earnings before interest, taxes, depreciation, and amortisation	US$(2021)
EBT	Earnings before taxes	US$(2021)
FIT	Feed-in tariff	US¢(2021)/ kWh
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$(2021) per year
p	Local electricity tariff	US¢(2021)/ kWh
P	Installed capacity	kW$_p$
r	Rate (for depreciation and tax)	%
T	Project lifetime	years
WACC	Weighted cost of capital	%

Index	Meaning
a	Annual
degr	Degradation
depr	Depreciation
end	Loan at end of year t
i	ith iteration to find solution for debt sizing and LCOE calculation
infl	Inflation
max	Maximum
min	Minimum
p	Peak
rated	-
sizing	DSCR used for debt sizing
start	Loan at start of year t
t	Year (out of total lifetime)
T	Total lifetime of plant

K.1. Debt sizing module

For year t from 1 to T = 20 years

norminv is the normal inverse cumulative probability function. Inputs for norminv are the percentile (10th percentile for p90 value) and the mean and standard deviation of the annual electricity production.

$$c_f(p90) = \frac{norminv(0.1, \bar{E}_a, \sigma_{Ea})}{8{,}760} \tag{K1}$$

$$E_{a,t}(p90) = P_{rated} * c_f(p90) * 8{,}760 * \left(1 - e_{degr}\right)^{t-1} \tag{K2}$$

$$Revenue_t = E_{a,t}(p90) * p \tag{K3}$$

$$EBITDA_t = Revenue_t - OPEX_t * \left(1 + e_{infl}\right)^{t-1} \tag{K4}$$

$$Depreciation_t = \begin{cases} CAPEX * r_{depr}, & t \leq T_{depr} \\ 0, & T > T_{depr} \end{cases} \tag{K5}$$

$$EBIT_t = EBITDA_t - Depreciation_t \tag{K6}$$

$$Loan_{i=1} = Loan_{Start,i=1} = CAPEX_t * d_{max} \tag{K7}$$

$$T_{loan,i=1} = T = 20\ years \tag{K8}$$

$$Interest_t = \begin{cases} Loan_i * CoD, & t = 1 \\ Loan_{Start,t} * CoD, & t > 1\ and\ t \leq T_{loan} \\ 0, & t > T_{loan} \end{cases} \tag{K9}$$

$$EBT_t = EBIT_t - Interest_t \tag{K10}$$

$$Tax_t = \begin{cases} 0, & EBT \leq 0 \\ EBT_t * r_{tax}, & EBT > 0 \end{cases} \tag{K11}$$

$$CFADS_t = EBITDA_t - Tax_t \tag{K12}$$

$$Debt\ Service_t = \frac{CFADS_t}{DSCR_{sizing,i}} \tag{K13}$$

$$Principal_t = \begin{cases} Debt\ Service_t - Interest_t, & t \leq T_{loan} \\ 0, & t > T_{loan} \end{cases} \tag{K14}$$

$$Loan_{End,t} = Loan_{Start,t} - Principal_t \tag{K15}$$

$$Loan_{Start,t+1} = Loan_{End,t} \tag{K16}$$

At $t = T_{loan,i}$ (initially 20 years). Tuning coefficient ¼ found via trial-and-error:

$$Loan_{i+1} = \begin{cases} Loan_i, & Loan_{End,t=Tloan,i} < 0 \\ Loan_i - \dfrac{Loan_{End,t=Tloan,i}}{4}, & Loan_{End,t=Tloan,i} > 0 \end{cases} \tag{K17}$$

If $\left| Loan_{End,t=Tloan,i} \right| > 1$:

$$d_{i+1} = \frac{Loan_{i+1}}{CAPEX} \tag{K18}$$

If $Loan_{End,t=Tloan,i} < 0$ *and i = 1 (first iteration):*

$$T_{loan,i+1} = year\ t\ where\ Loan_{end,t} < 0\ for\ the\ first\ time \tag{K19}$$

If $Loan_{End,t=Tloan,i} < 0$ *and i > 1 (loan repayment period has already been adjusted), Tuning coefficient 1/3.6 found via trial-and-error:*

$$DSCR_{sizing,i+1} = \frac{Loan_{End,t=Tloan,i}}{Loan_i * 3.6} + DSCR_{siing,i} \tag{K20}$$

Repeat until all of the following apply:

- $d_i \leq d_{max}$
- $DSCR_{sizing,i} \geq DSCR_{min}$
- $\left| \, Loan_{End,t=T} \right| \leq 1$

K.2. Cash flow analysis module

For year t from 1 to T

$$Revenue_t = E_{a,t} * p \qquad (K21)$$

$$EBITDA_t = Revenue_t - OPEX_t * \left(1 + e_{infl}\right)^{t-1} \qquad (K22)$$

$$Depreciation_t = \begin{cases} CAPEX * r_{depr}, & t \leq T_{depr} \\ 0, & T > T_{depr} \end{cases} \qquad (K23)$$

$$EBIT_t = EBITDA_t - Depreciation_t \qquad (K24)$$

$$EBT_t = EBIT_t - Interest_t \qquad (K25)$$

$$Tax_t = \begin{cases} 0, & EBT_t \leq 0 \\ EBT_t * r_{tax}, & EBT_t > 0 \end{cases} \qquad (K26)$$

$$FCFE_t = EBT_t - Tax_t - Principal_t + Depreciation_t \qquad (K27)$$

For project-related metrics, the tax is calculated without debt service.

$$Tax_t = \begin{cases} 0, & EBIT_t \leq 0 \\ EBIT_t * r_{tax}, & EBIT_t > 0 \end{cases} \qquad (K28)$$

$$WACC = r_{Debt} * CoD + (1 - r_{Debt}) * CoE \qquad (K29)$$

$$NPV = \frac{-CAPEX * (1 - r_{Debt}) + \sum_{t=1}^{T} \frac{FCFE_t}{(1 + CoE)^t}}{P_{rated}} \qquad (K30)$$

$$0 = NPV = -CAPEX * (1 - r_{Debt}) + \sum_{t=1}^{T} \frac{FCFE_t}{(1 + IRR)^t} \qquad (K31)$$

$$DSCR_t = \frac{EBITDA_t - Tax_t}{Interest_t + Principal_t} \qquad (K32)$$

The LCOE is determined iteratively with a constant CoE starting with an initial tariff of 20 US¢/kWh, the equations are looped over j iterations until $| LCOE_j - LCOE_{j-1} | < 0.1$.

$$LCOE = \sum_{t=1}^{T} \frac{Annual\ Cost}{Annual\ Production} = \frac{CAPEX * (1 - r_{Debt}) + \sum_{t=1}^{T} \frac{Revenue_t - FCFE_t}{(1 + CoE)^t}}{\sum_{t=1}^{T} \frac{E_{a,t}}{(1 + CoE)^t}} \qquad (K33)$$

L. Setting up pyOTEC (chapter 6)

Here, we describe how to set up pyOTEC. First, we recommend users to install the latest version of Anaconda as it contains most of the libraries used by pyOTEC. Then, the netCDF4 library needs to be installed via Anaconda prompt. Next, the pyOTEC repository needs to be downloaded from GitHub (https://github.com/JKALanger/pyOTEC). Before using pyOTEC, the user needs to register and create an account at Copernicus Marine Service [48] and install the Python package *motuclient*. The account credentials (username and password) are needed for authentication and can either be hardcoded in pyOTEC or stored in a separate callable file. The MOTU API is needed to automatically request and download the data as *"nc files"* (a standard data format that allows for the efficient storage of large datasets resolved in space and time). Then, the user opens the file pyOTEC.py in their preferred Python IDE, e.g. Spyder. To start the analysis, the user needs to provide the region and plant size as gross power output. If the user wants to check and change the inputs used by pyOTEC, they can do so in the files parameters_and_constants.py and capex_opex_lcoe.py.

M. Processing of seawater temperature data by pyOTEC (chapter 6)

After the successful download of the seawater temperature data, pyOTEC processes the data further. The data of the raw nc files spreads over the rectangular shape of the region's geographical extent, thus also covering land areas and marine areas unsuitable for OTEC. pyOTEC checks the coordinates of the raw temperature profiles with the coordinates of the technically feasible OTEC sites mapped in section 2.2, and discards the profiles with no match. Then, outliers and faulty values in the profiles (e.g. negative temperatures) are replaced by NaN. Here, we define outliers as values that are more than 3 times the interquartile range away from the profiles' minima and maxima. In Langer et al. [304], we used a factor of 1.5 for Indonesia, but after trial-and-error with the more extensive and diverse global temperature datasets, we found a factor 3 to be more suitable for removing outliers without removing rare, but not impossible, extreme temperature values. Outliers are detected using a one-month rolling time window. All NaN are filled via linear interpolation. The processed temperature profiles and design values for each OTEC site are stored as h5 files (an open-source data format that allows for the storage of several large datasets in one file).

N. List of equations used by pyOTEC (chapter 6)

Symbols and Indices

Symbol	Meaning	Unit ([-] if unitless)
Δ	Difference	-
ε	Effectiveness	%
η	Efficiency	%
λ	Thermal conductivity	W/Km
μ	Dynamic viscosity	Pa s
ρ	Density	kg/m^3
b	Scale factor	-
A	Area	m^2
AEP	Annual electricity production	kWh/year
$capex$	Specific capital expenses	variable
$CAPEX$	Capital expenses	US$(2021)
c	Specific heat capacity	kJ/kgK
cf	Capacity factor	%
CRF	Capital recovery factor	%
d	Diameter	m
D	Distance plant to shore	km
DR	Discount rate	%
Ex	Exergy	kW
f	Friction factor	-
h	Enthalpy	kJ/kg
K	Pressure drop coefficient	-
l	Length	m
$LCOE$	Levelized cost of electricity	US¢(2021)/ kWh
m	Mass	kg
$\dot{m}$	Mass flow	kg/s
N	Number of pipes	-
n	Project lifetime	years
NTU	Number of transfer units	-
$OPEX$	Operational expenses	US$(2021) per year
p	Pressure	Pa
Pr	Prandtl number	-
$\dot{Q}$	Heat	kW
Re	Reynolds number	-
s	Entropy	kJ/kgK
t	Thickness	m
T	Temperature	K, °C
U	Overall heat transfer coefficient	kW/m^{2}K
v	Velocity	m/s
$\dot{W}$	Power	kW
x	Vapour quality	%
z	Roughness	mm

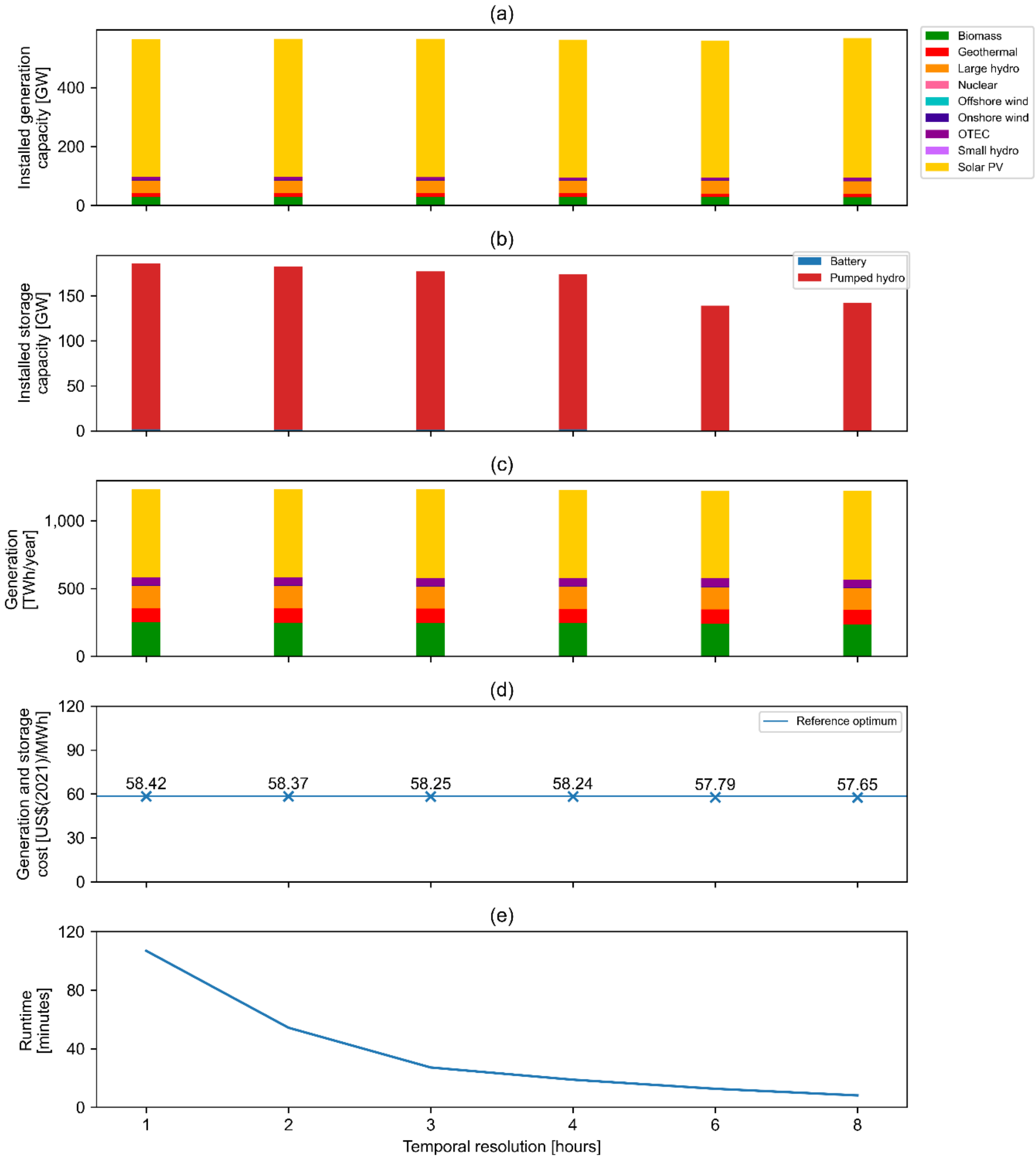
Index	Meaning
0	Reference
cond	Condenser
CW	Cold water
D	Darcy
depl	Deployment
des	Design & Management
el	Electrical
evap	Evaporator
ext	Extra
gen	Generator
HX	Heat exchanger
i	Year
is	Isentropic
L	Loss
liq	Liquid
log	Logarithmic
max	Maximum
mech	Mechanical
NH_3	Ammonia
nom	Nominal
p	Pressure
pp	Pinch Point
sat	Saturation
struct	Structure & Mooring
t	Technical
tot	Total
trans	Transmission
turb	Turbine
W	Wall
WW	Warm water

Value	Equation
Saturation Temperature & Pressure, Enthalpy and Entropy of Ammonia (NH_3)	
Saturation Temperature T_{sat} [°C]	$T_{evap} = T_{WW,in} - \Delta T_{WW} - \Delta T_{pp}$ $T_{cond} = T_{CW,in} + \Delta T_{CW} + \Delta T_{pp}$
Saturation pressure p_{sat} [bar] (approximation function based on saturation table)	$p_{sat}(T_{sat}) = 2.196 * 10^{-5} * T_{sat}^3 + 1.93103 * 10^{-3} * T_{sat}^2 + 0.1695763 * T_{sat} + 4.257339601$
Enthalpy liquid phase h' [kJ/kg] (approximation function based on saturation table)	$h'(p_{sat}) = -0.0235 * p_{sat}^4 + 0.9083 * p_{sat}^3 - 12.93 * p_{sat}^2 + 97.316 * p_{sat} - 39.559$
Enthalpy vapour phase h'' [kJ/kg] (approximation function based on saturation table)	$h''(p_{sat}) = 28.276 * \ln(p_{sat}) + 1418.1$
Entropy liquid phase s' [kJ/kgK] (approximation function based on saturation table)	$s'(p_{sat}) = 0.3947 * \ln(p_{sat}) + 0.4644$
Entropy vapour phase s'' [kJ/kgK] (approximation function based on saturation table)	$s''(p_{sat}) = -0.352 * \ln(p_{sat}) + 6.1284$
Turbine + Generator + Power Transmission	
Isentropic quality at turbine outlet $x_{turb,out,is}$ [%]	$x_{turb,out,is} = \frac{s_{turb,in} - s'_{turb,out}}{s''_{turb,out} - s'_{turb,out}}$
Isentropic enthalpy at turbine outlet $h_{turb,out,is}$ [kJ/kg]	$h_{turb,out,is} = h' * \left(1 - x_{turb,out,is}\right) + h'' * x_{turb,out,is}$
Enthalpy at turbine outlet $h_{turb,out}$ [kJ/kg]	$h_{turb,out} = \left(h_{turb,out,is} - h_{turb,in}\right) * \eta_{is,turb} + h_{turb,in}$
Mass flow ammonia $\dot{m}_{NH_3}$ [kg/s]	$\dot{m}_{NH_3} = \frac{\dot{W}_{t,turb,gross}}{h_{turb,out} - h_{turb,in}}$
Transmission efficiency η_{trans} [%] (D being distance from plant to shore)	$\eta_{Trans} = \begin{cases} 0.979 - 1 * 10^{-6} * D^2 - 9 * 10^{-5} * D, & D \leq 50\ km \\ 0.964 - 8 * 10^{-5} * D, & D > 50\ km \end{cases}$
Ammonia Pump	
Enthalpy at pump outlet $h_{pump,out}$ [kJ/kg]	$h_{pump,out} = \frac{p_{evap} - p_{cond}}{\rho_{NH_3,liq} * \eta_{is,pump}} + h_{pump,in}$
Pump power consumption $\dot{W}_{t,pump,NH_3}$ [kW]	$\dot{W}_{t,pump,NH_3} = \dot{m}_{NH_3} * \frac{h_{pump,out} - h_{pump,in}}{\eta_{el,pump}}$
Evaporator	
Logarithmic temperature difference $\Delta T_{log,evap}$ [K]	$\Delta T_{log,evap} = \frac{\left(T_{WW,in} - T_{evap}\right) - \left(\left(T_{WW,in} - \Delta T_{WW}\right) - T_{evap}\right)}{\ln\left(\frac{T_{WW,in} - T_{evap}}{\left(T_{WW,in} - \Delta T_{WW}\right) - T_{evap}}\right)}$
Evaporation heat $\dot{Q}_{evap}$ [kW]	$\dot{Q}_{evap} = \dot{m}_{NH_3} * (h_{evap,out} - h_{evap,in})$
Mass flow warm seawater $\dot{m}_{WW}$ [kg/s]	$\dot{m}_{WW} = \frac{\dot{Q}_{evap}}{c_{p,H_2O} * \Delta T_{WW}}$
Heat transfer area evaporator A_{evap} [m²]	$A_{evap} = \frac{\dot{Q}_{evap}}{U_{evap} * \Delta T_{log,evap}}$
Condenser	
Logarithmic temperature difference $\Delta T_{log,cond}$ [K]	$\Delta T_{log,cond} = \frac{\left(T_{cond} - T_{CW,in}\right) - \left(T_{cond} - \left(T_{CW,in} + \Delta T_{CW}\right)\right)}{\ln\left(\frac{T_{cond} - T_{CW,in}}{T_{cond} - \left(T_{CW,in} + \Delta T_{CW}\right)}\right)}$
Condensation heat $\dot{Q}_{cond}$ [kW]	$\dot{Q}_{cond} = \dot{m}_{NH_3} * (h_{cond,out} - h_{cond,in})$
Mass flow cold seawater $\dot{m}_{CW}$ [kg/s]	$\dot{m}_{CW} = \frac{\lvert\dot{Q}_{cond}\rvert}{c_{p,H_2O} * \Delta T_{CW}}$
Heat transfer area condenser A_{cond} [m²]	$A_{cond} = \frac{\lvert\dot{Q}_{cond}\rvert}{U_{cond} * \Delta T_{log,cond}}$

(continued)

Variable	Equation
Seawater Pipes (for both WW and CW)	
Required total inner pipe area A_{tot} [m^2]	$A_{tot} = \frac{\dot{m}_{WW/CW}}{\rho_{H2O} * v_{WW/CW}}$
Inner diameter d_{pipe} [m]	$d_{pipe} = \sqrt{\frac{4*A_{tot}}{\pi*N_{pipe}}}$
Number of pipes N_{pipe} [-]	Increase N_{pipe} in steps of 1 until $d_{pipe} \leq d_{max}$
Mass of pipes m_{pipe} [kg]	$m_{pipe} = \frac{\pi}{4} * \left(\left(d_{pipe} + 2 * t\right)^2 - d_{pipe}^2\right) * l_{pipe} * \rho_{HDPE/FPR} * N_{pipe}$
Dynamic viscosity seawater μ [Pa*s] (Approximation function based on state table)	$\mu = 3.443 * 10^{-7} * T^2 - 4.711 * 10^{-5} * T + 1.767 * 10^{-3}$
Reynolds number Re [-]	$Re = \frac{\rho_{WW/CW} * v_{WW/CW} * d_{pipe}}{\mu_{WW/CW}}$
Darcy friction factor f_D [-] (Swamee-Jain equation)	$f_D = \frac{0.25}{\left(\log_{10}\left(\frac{z}{3.7 * d_{pipe}} + \frac{5.74}{Re^{0.9}}\right)\right)^2}$
Pressure drop in pipe Δp_{pipe} [Pa]	$\Delta p_{pipe} = f_D * \rho_{WW/CW} * \frac{l_{pipe}}{d_{pipe}} * \frac{v_{pipe}^2}{2}$
Pressure drop in heat exchanger $\Delta p_{evap/cond}$ [Pa]	$\Delta p_{evap/cond} = \rho_{WW/CW} * \frac{v_{evap/cond}^2}{2} * K_{L,evap/cond}$
Power consumption seawater pump $\dot{W}_{t,pump}$ [kW]	$\dot{W}_{t,pump} = \frac{\dot{m}_{CW} * \left(\Delta p_{pipe} + \Delta p_{evap,cond}\right)}{\rho_{H2O} * \eta_{is,pump} * \eta_{el,pump}}$
Net Power and Efficiency	
Net Power Production $\dot{W}_{t,net}$ [kW]	$\dot{W}_{t,net} = \frac{\left(\dot{W}_{t,turb,gross} * \eta_{mech,turb} * \eta_{el,turb} + \dot{W}_{t,pump,NH_3} + \dot{W}_{t,pump}\right)}{\eta_{trans}}$
Net Thermal Efficiency η_{net} [%]	$\eta_{net} = \frac{\lvert \dot{W}_{t,net} \rvert}{\dot{Q}_{evap}}$
LCOE	
Capital Recovery Factor CRF [%]	$CRF = \frac{DR * (1 + DR)^n}{(1 + DR)^n - 1}$
Scaled specific capital expenses $capex$ [US\$ million/unit]	$capex_i = capex_0 * \left(\frac{\dot{W}_{t,gross,0}}{\dot{W}_{t,gross,i}}\right)^b$
CAPEX without extra costs [US\$ million] (sum of H cost components. Unit can be gross power output, power consumption, mass or area)	$CAPEX_{no\ extra} = \sum_{h=1}^{H} capex_h * unit_h$
Total $CAPEX$ [US\$ million]	$CAPEX_{total} = CAPEX_{no\ extra} * (1 + perc_{ext})$
Annual Electricity Production AEP [kWh/year]	$AEP = \begin{cases} \lvert \dot{W}_{t,net,nom} \rvert * c_f * 8760, & On - Desin \\ \sum_{m}^{M} \dot{W}_{t,net,m} * 365, & Off - Design \end{cases}$
Levelised Cost of Electricity $LCOE$ [US¢/kWh]	$LCOE = \frac{CRF * CAPEX + OPEX}{AEP}$

O. Impact of temporal downsampling in chapter 7



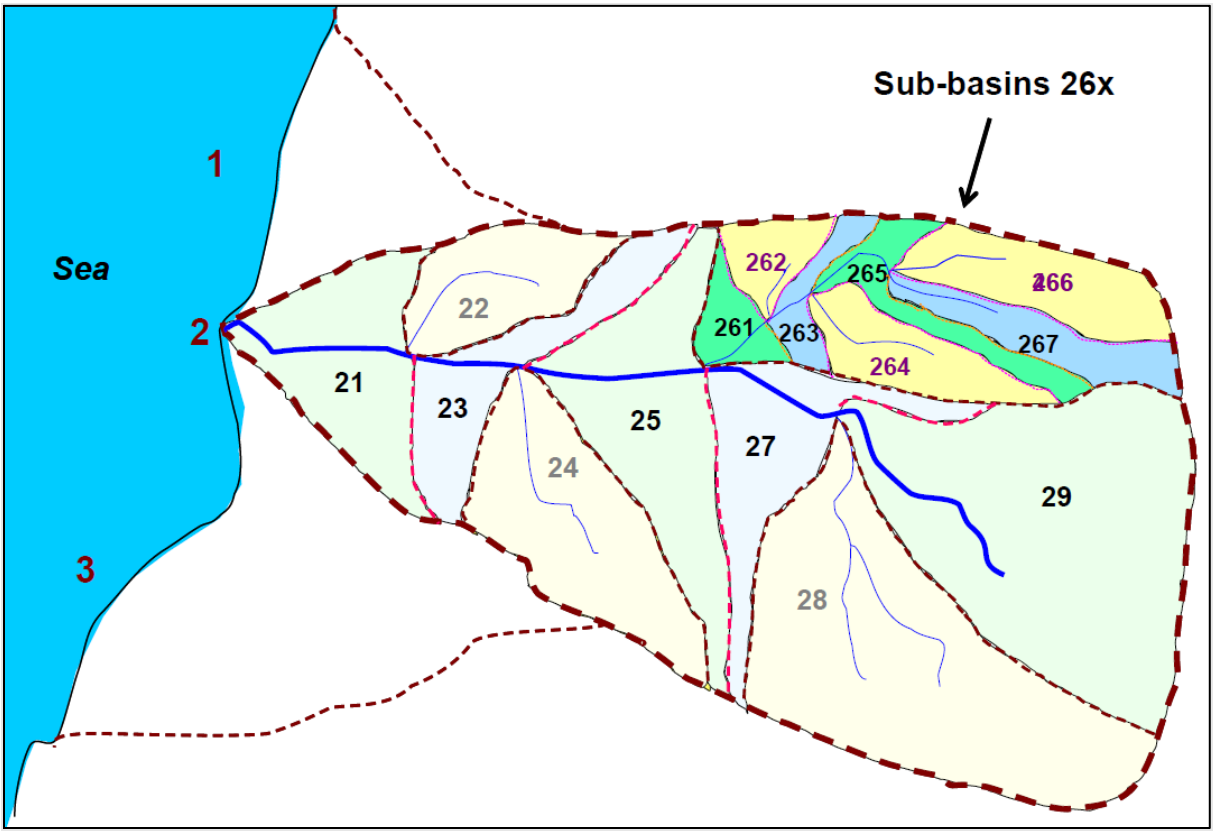
The impact of temporal resolution on installed (a) generation and (b) storage capacity, (c) electricity generation, (d) levelised generation and storage cost, and (e) model runtime.

P. Hourly hydropower production profiles using bias correction (chapter 7)

For hydropower, we use the publicly available dataset for hydropower plant locations and their mean river discharge and hydraulic head by Hoes et al. [49]. To convert the single-value river discharge into hourly time series, we use ERA5 runoff data and the methods by Liu et al. [347] as follows.

First, we detect the upstream basins of each hydropower plant using the HydroBASINS dataset [373] and Pfafstetter coding system. Put simply, this system assigns identification numbers to basins based on their location on the river, see the figure below. If the code's last digit is odd, the basin contains the river's main stem. If the last digit is even, the basin contains the tributary of the main stem (i.e. a branch of the main river). If the last digit is zero, the basin is not connected to the main stem at all. The higher the last digit, the more upstream the basin is located on the river (1: most downstream; 9: most upstream). The basins can be subdivided into smaller basins and then coded in the same way for higher precision. In that case, the applicable number is appended to the original basins' code. For example, the most downstream sub-basin of basin *858* (level 3) has the code *8581* (level 4).

Upstream basins can be determined by iteratively checking the last digit of a basin's Pfafstetter code and removing its last digit. Liu et al. [347] did this for levels 5 to 7. After trial-and-error and in line with Gøtske & Victoria [374], we use level 8 basins to detect upstream basins without iterating to lower levels.



Pfafstetter coding system [375].

After obtaining the upstream basins, we aggregate the hourly runoff profiles of all ERA5 points that overlap with these basins. If an ERA5 point only partially covers a basin, we calculate the fraction of the overlapping area. For example, if only 25% of an ERA5 point overlaps with a basin, only 25% of the respective runoff data is used for aggregation.

After this step, we know the total runoff across each basin, but not yet the river discharge at the plant's location. For this, we aggregate the runoff of all upstream basins and then calculate the annual mean. Then, we compare the mean with the mean discharge value at the plant's location calculated by Hoes et al. [49] to obtain a correction factor. Each time step of the runoff data is then multiplied with the correction factor.

Next, we calculate the hydropower plant's rated power P_{rated} using Eq. (I) with water density ρ=1,000 kg/m^3, gravity g=9.81 m/s^2, mean river discharge Q, and hydraulic head H.

$$P_{rated} = \rho * g * Q * H \qquad (I)$$

The hourly power production P_t is also calculated with Eq. (I), but then with the hourly river discharge Q_t. If $P_t > P_{rated}$, the power production at that time step is capped to P_{rated}.

This approach captures the essence of what leading open-source ESOM like PyPSA [376] are doing. Nevertheless, we acknowledge that this method only delivers ballpark numbers on hourly hydropower production profiles. Liu et al. [347] found correction factors beyond 1,000 when comparing their modelled runoff with empirically measured river data. Our main goal is to capture seasonal fluctuations in hydropower availability, especially during Indonesia's dry season, and we perceive a limited level of accuracy as acceptable.

Q. Cost assumptions from literature (chapter 7)

Q1. CAPEX

Values for present CAPEX per technology in [US$(2021)/kW] for generators and [US$(2021)/MWh] for storage used in Indonesian ESOM and resource mapping literature published since 2016.

[Ref]	Coal	Diesel	CCGT	OCGT	Large hydro	Bio-mass	Geo-thermal	Small hydro	Solar PV	Onshore wind	Offshore wind	Nuclear	OTEC	Battery	PHES
[25]	2,090	-	914	491	2,462	2,494	2,994	3,750	2,186	1,965	-	4,440	-	-	-
[36]	2,019	-	895	783	2,239	2,494	3,917	2,686	-	2,462	-	6,716	-	-	-
[377]	-	-	-	-	-	-	-	2,002	2,314	-	-	-	-	-	-
[370]	2,449	-	1,109	-	-	1,792	2,645	-	1,194	1,664	-	4,607	-	-	-
[66]	1,559	-	-	-	-	-	-	-	987	1,819	-	-	-	-	-
[203]	1,546	883	828	850	2,208	1,877	3,864	2,871	916	1,656	-	-	-	276,028	22,082
[280]	1,546	883	762	850	2,297	2,208	4,416	2,981	872	1,656	-	-	-	-	-
[378]	3,232	700	1,077	943	-	3,070	5,601	-	1,333	1,534	-	9,856	-	-	-
[359]	1,343	448	783	448	2,574	2,574	2,574	3,470	2,015	1,567	-	-	-	-	-
[379]	-	-	-	-	1,819	2,078	4,070	2,078	1,203	2,461	-	-	-	-	-
[380]	1,303	-	-	-	-	1,312	4,157	2,061	998	-	-	-	-	-	-
[290]	-	-	-	-	2,000	2,100	3,991	2,200	1,264	1,545	-	-	-	-	-
[349]	2,950	-	1,000	813	-	-	4,950	-	875	1,188	-	10,300	-	-	-
[27]	1,455	-	624	779	2,286	3,325	2,301	-	1,143	2,006	-	-	-	-	-
[232]	-	-	-	-	-	-	-	-	-	-	4,325	-	-	-	-
[304]	-	-	-	-	-	-	-	-	-	-	-	-	6,668	-	-
[28]	-	-	-	-	-	-	-	-	-	-	-	-	-	372,717	-
Minimum	1,303	448	624	448	1,819	1,312	2,301	2,002	872	1,188	4,325	4,440	6,668	276,028	22,082
Median	1,559	792	895	798	2,263	2,208	3,954	2,686	1,194	1,660	4,325	6,716	6,668	324,373	22,082
Maximum	3,232	883	1,109	943	2,574	3,325	5,601	3,750	2,314	2,462	4,325	10,300	6,668	372,717	22,082

Q2 Fixed OPEX

Values for present fixed OPEX per technology in [US$(2021)/kW/year] for generators and [US$(2021)/MWh/year] for storage used in Indonesian ESOM and resource mapping literature published since 2016.

[Ref]	Coal	Diesel	CCGT	OCGT	Large hydro	Bio-mass	Geo-thermal	Small hydro	Solar PV	Onshore wind	Offshore wind	Nuclear	OTEC	Battery	Pumped hydro
[25]	71.6	-	26.9	23.5	62.7	87.3	59.3	75.0	22.4	49.2	-	183.6	-	-	-
[377]	-	-	-	-	-	-	-	54.0	27.7	-	-	-	-	-	-
[370]	39.4	-	17.1	-	-	82.8	41.0	-	17.9	51.2	-	68.3	-	-	-
[203]	45.5	8.8	25.6	25.6	41.6	52.6	19.9	58.5	16.6	66.2	-	-	-	7,729	221
[280]	45.5	8.8	25.9	25.6	41.6	52.6	55.2	58.5	15.9	66.2	-	-	-	-	-
[378]	43.1	10.8	6.3	13.5	-	53.9	-	-	11.3	37.7	-	145.4	-	-	-
[359]	53.7	31.3	28.0	22.4	60.4	108.6	44.8	68.3	25.7	41.4	-	-	-	-	-
[379]	-	-	-	-	45.5	83.1	-	52.0	9.9	-	-	-	-	-	-
[290]	-	-	-	-	50	84	-	55	9.6	31	-	-	-	-	-
[349]	36.3	-	16.5	14.1	-	-	13	-	11.3	30.8	-	130.8	-	-	-
[27]	46.8	8.3	20.8	10.4	39.5	-	49.9	-	27.0	62.4	-	-	-	-	-
[232]	-	-	-	-	-	-	-	-	-	-	20.1	-	-	-	-
[304]	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-
[28]	-	-	-	-	-	-	-	-	-	-	-	-	-	11,182	-
Minimum	36.3	8.3	6.3	10.4	39.5	52.6	13	52	9.6	30.8	20.1	68.3	200	7,729	221
Median	45.5	8.8	23.2	22.4	45.5	83.0	44.8	58.5	16.6	49.2	20.1	138.1	200	9,456	221
Maximum	71.6	31.3	28	25.6	62.7	108.6	59.3	75	27.7	66.2	20.1	183.6	200	11,182	221

Q3. Variable OPEX

Values for present variable OPEX per technology in [US$(2021)/MWh/year] for generators and storage used in Indonesian ESOM and resource mapping literature published since 2016.

[Ref]	Coal	Diesel	CCGT	OCGT	Large hydro	Bio-mass	Geo-thermal	Small hydro	Solar PV	Onshore wind	Offshore wind	Nuclear	OTEC	Battery	Pumped hydro
[370]	2.99	-	1.28	-	-	5.55	0.60	-	-	-		1.71	-	-	-
[203]	0.13	7.07	0.14	0.12	0.72	3.31	0.28	0.55	-	-	-	-	-	-	1.44
[280]	0.13	7.07	2.54	-	0.72	3.31	0.28	0.55	-	-	-	-	-	-	-
[378]	3.77	10.77	2.96	7.92	-	10.77	37.70	-	-	-	-	0.81	-	-	-
[359]	4.25	4.25	4.25	4.25	4.25	7.28	0.78	4.25	0.45	0.90	-	-	-	-	-
[379]	-	-	-	-	-	5.20	-	-	-	-	-	-	-	-	-
[290]	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-
[349]	2	-	3.88	4.63	-	-	15	-	-	-	-	4.25	-	-	-
[27]	-	-	15.59	15.59	-	-	-	-	-	-	-	-	-	-	-
[232]	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-
[304]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
[28]	-	-	-	-	-	-	-	-	-	-	-	-	-	0.25	-
Minimum	0.13	4.25	0.14	0.12	0.72	3.31	0.28	0.55	0.45	0.9	25	0.81	-	0.25	1.44
Median	2.5	7.07	2.96	4.63	0.72	5.2	0.69	0.55	0.45	0.9	25	1.71	-	0.25	1.44
Maximum	4.25	10.77	15.59	15.59	4.25	10.77	37.7	4.25	0.45	0.9	25	4.25	-	0.25	1.44

R. Cost projections until 2050 from literature (chapter 7)

R1. CAPEX

*Projections for CAPEX until 2050 from literature in [% of 2020 cost]. 2040 projections are determined by linear interpolation between 2030 and 2050 values. * In Ref* [348], *the battery cost in 2030 are given as 205 €/kWh, which would be 80.4% of 2020 cost and thus inconsistent with the report's 2040 and 2050 battery costs (97.5% and 96.3% of 2020 costs, respectively). Therefore, we interpolated between the reports 2020, 2040, and 2050 costs to estimate the 2030 battery costs.*

[Ref]	Coal	Diesel	CCGT	OCGT	Large hydro	Bio-mass	Geo-thermal	Small hydro	Solar PV	Onshore wind	Offshore wind	Nuclear	OTEC	Battery	Pumped hydro
								2030							
[28]	100%	-	100%	100%	-	88.9%	-	-	67.2%	87.0%	-	-	-	50%	-
[60]	90.1%	100%	90.1%	94.2%	100%	82.5%	94.7%	100%	64.2%	93.5%	-	-	-	-	-
[348]	100%	-	100%	100%	100%	89.6%	89.9%	100.4%	80.0%	96.3%	89.6%	94.3%	-	98.8%*	100%
[280]	97%	100%	95.7%	94.8%	96.2%	91.0%	86.0%	95.9%	70.9%	85.3%	85.1%	-	-	45.7%	100%
[19]	-	-	-	-	-	-	-	-	-	-	-	-	81.3% 90.7% 100%	-	-
Minimum	90.1%	100%	90.1%	94.2%	96.2%	82.5%	86.0%	95.9%	64.2%	85.3%	85.1%	94.3%	81.3%	45.7%	100%
Median	98.5%	100%	97.9%	97.4%	100%	89.3%	89.9%	100%	69.1%	90.3%	87.4%	94.3%	90.7%	47.9%	100%
Maximum	100%	100%	100%	100%	100%	91.0%	94.7%	100.4%	80.0%	96.3%	89.6%	94.3%	100%	50.0%	100%
								2050							
[28]	100%	-	100%	100%	-	69.8%	-	-	42.4%	78.3%	-	-	-	25.0%	-
[60]	85.1%	100%	75.2%	82.5%	100%	71.3%	85.3%	100%	43.7%	85.0%	-	-	-	-	-
[348]	100%	-	100%	100%	100%	67.2%	72.6%	100.4%	65.0%	81.5%	79.2%	86.2%	-	96.3%	100%
[280]	93.9%	97.5%	88.4%	88.3%	88.9%	80.0%	71.0%	88.9%	51.9%	72.0%	72.0%	-	-	27.2%	100%
[19]	-	-	-	-	-	-	-	-	-	-	-	-	49.1% 74.6% 100%	-	-
Minimum	85.1%	97.5%	75.2%	82.5%	88.9%	67.2%	71.0%	88.9%	42.4%	72.0%	72.0%	86.2%	49.1%	25.0%	100%
Median	97.0%	98.8%	94.2%	94.2%	100%	70.6%	72.6%	100%	47.8%	79.9%	75.6%	86.2%	74.6%	27.2%	100%
Maximum	100%	100%	100%	100%	100%	80.0%	85.3%	100.4%	65.0%	85.0%	79.2%	86.2%	100%	96.3%	100%

R2. Fixed OPEX

Projections for fixed OPEX until 2050 from literature in [% of 2020 cost].

[Ref]	Coal	Diesel	CCGT	OCGT	Large hydro	Bio-mass	Geo-thermal	Small hydro	Solar PV	Onshore wind	Offshore wind	Nuclear	OTEC	Battery	Pumped hydro
								2030							
[28]	100%	-	100%	100%	-	88.8%	-	-	80%	87.0%	-	-	-	41.7%	-
[348]	100%	-	100%	100%	100%	100%	101.2%	100.4%	80%	88.3%	84.0%	85.3%	-	80.4%	100%
[280]	96.9%	100%	97.0%	97.0%	96.0%	92.0%	86.0%	95.9%	69.4%	85.0%	85.0%	-	-	50.1%	100%
[19]	-	-	-	-	-	-	-	-	-	-	-	-	81.3% 90.7% 100%	-	-
Minimum	96.9%	100%	97.0%	97.0%	96.0%	88.8%	86.0%	95.9%	69.4%	85.0%	84.0%	85.3%	81.3%	41.7%	100%
Median	100%	100%	100%	100%	98.0%	92.0%	93.6%	98.2%	80.0%	87.0%	84.5%	85.3%	90.7%	50.1%	100%
Maximum	100%	100%	100%	100%	100%	100%	101.2%	100.4%	80.0%	88.3%	85.0%	85.3%	100%	80.4%	100%
								2050							
[28]	100%	-	100%	100%	-	69.7%	-	-	53.3%	78.3%	-	-	-	20.8%	-
[348]	100%	-	100%	100%	100%	100%	99.9%	100.4%	65.0%	57.7%	56.9%	65.7%	-	96.3%	100%
[280]	94.0%	97.0%	94.0%	94.0%	89.1%	80.0%	71.0%	89.0%	55.6%	72.0%	72.0%	-	-	25.0%	100%
[19]	-	-	-	-	-	-	-	-	-	-	-	-	49.1% 74.6% 100%	-	-
Minimum	94.0%	97.0%	94.0%	94.0%	89.1%	69.7%	71.0%	89.0%	53.3%	57.7%	56.9%	65.7%	49.1%	20.8%	100%
Median	100%	97.0%	100%	100%	94.6%	80.0%	85.5%	94.7%	55.6%	72.0%	64.5%	65.7%	74.6%	25.0%	100%
Maximum	100%	97.0%	100%	100%	100%	100%	99.9%	100.4%	65.0%	78.3%	72.0%	65.7%	100%	96.3%	100%

R3. Variable OPEX

Projections for variable OPEX until 2050 from literature in [% of 2020 cost].

[Ref]	Coal	Diesel	CCGT	OCGT	Large hydro	Bio-mass	Geo-thermal	Small hydro	Solar PV	Onshore wind	Offshore wind	Nuclear	OTEC	Battery	Pumped hydro
								2030							
[28]	100%	-	-	-	-	100%	-	-	-	-	-	-	-	100%	-
[348]	100%	-	100%	100%	100%	100%	-	100%	-	-	-	100%	-	100%	-
[280]	92.3%	93.8%	-	-	96.0%	93.3%	-	96.0%	-	-	87.3%	-	-	90.0%	100%
Minimum	92.3%	93.8%	100%	100%	96.0%	93.3%	-	96.0%	-	-	87.3%	100%	-	90.0%	100%
Median	100%	93.8%	100%	100%	98.0%	100%	-	98.0%	-	-	87.3%	100%	-	100%	100%
Maximum	100%	93.8%	100%	100%	100%	100%	-	100%	-	-	87.3%	100%	-	100%	100%
								2050							
[28]	100%	-	-	-	-	100%	-	-	-	-	-	-	-	100%	-
[348]	100%	-	100%	100%	100%	100%	-	100%	-	-	-	100%	-	100%	-
[280]	92.3%	90.6%	-	-	89.2%	80.0%	-	90.0%	-	-	70.9%	-	-	80%	100%
Minimum	92.3%	90.6%	100%	100%	89.2%	80.0%	-	90.0%	-	-	70.9%	100%	-	80.0%	100%
Median	100%	90.6%	100%	100%	94.6%	100%	-	95.0%	-	-	70.9%	100%	-	100%	100%
Maximum	100%	90.6%	100%	100%	100%	100%	-	100%	-	-	70.9%	100%	-	100%	100%

S. OTEC upscaling scenario (chapter 7)

Upscaling scenario for OTEC towards full commercial scale based on the original upscaling scenarios for Indonesia by Langer et al. [19]. *Underlying assumptions include a learning rate of 7% per doubling of installed capacity, and an installation growth rate of 22% p.a. from a global starting capacity of 10 MW_{gross}. CAPEX were re-calculated with the pyOTEC model* [346], *which did not exist yet at the time of the upscaling study* [19].

Year	Global installed OTEC capacity [GW_{gross}]	Cost reduction [% of 2021 CAPEX]	CAPEX [US$(2021)/$kW_{gross}$]
2023	0.01	100%	6,668
2025	0.02	93%	6,202
2030	0.07	81.3%	5,421
2035	0.24	71.6%	4,774
2040	0.85	63.1%	4,208
2045	2.92	55.7%	3,714
2050	9.95	49.1%	3,274

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In German, there is the small, yet significant, difference between *Beruf* and *Berufung*. The former means “profession” and makes you get out of bed, commute in a tightly packed train, drink the sub-par coffee from the vending machine, and what pays the bills. The latter means “calling” and encompasses all the things that drive you, give you purpose, fulfil you and make you look forward to Monday. I found my calling in the Thermodynamics lectures during my Bachelor studies and knew that the field of energy is where I belong. I feel privileged that my PhD did not feel like a job for most parts, but like an adventure. Nonetheless, it is not only the subject matter, but also the people that made this journey so special. To those who helped, supported, comforted, celebrated, and laughed with me, the following words are for you.

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Data Availability
The datasets, code, and Supplementary Files to this dissertation can be found at the repository 4TU.ResearchData under https://data.4tu.nl/authors/6c318b48-99b8-4711-ad76-ba167a865702.

List of publications

Published and submitted peer-reviewed journal articles

- Langer J, Lombardi F, Pfenninger S, Rahayu HP, Al Irsyad MI, Blok K. Full decarbonisation scenarios for Indonesia's power sector. Under review 2023.
- Langer J, Blok K. The global techno-economic potential of floating, closed-cycle ocean thermal energy conversion. J Ocean Eng Mar Energy 2023. https://doi.org/https://doi.org/10.1007/s40722-023-00301-1.
- Langer J, Kwee Z, Zhou Y, Isabella O, Ashqar Z, Quist J, Praktiknjo A, Blok K. Geospatial analysis of Indonesia's bankable utility-scale solar PV potential using elements of project finance. Energy 2023;283:128555. https://doi.org/10.1016/j.energy.2023.128555.
- 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.
- Langer J, Simanjuntak S, Pfenninger S, Laguna AJ, Lavidas G, Polinder H, Quist J, Rahayu HP, Blok K. How offshore wind could become economically attractive in low-resource regions like Indonesia. IScience 2022;25:104945. https://doi.org/10.1016/j.isci.2022.104945.
- Langer J, Infante Ferreira C, Quist J. Is bigger always better? Designing economically feasible ocean thermal energy conversion systems using spatiotemporal resource data. Appl Energy 2022;309:118414. https://doi.org/10.1016/j.apenergy.2021.118414.
- Langer J, Quist J, Blok K. Upscaling scenarios for ocean thermal energy conversion with technological learning in Indonesia and their global relevance. Renew Sustain Energy Rev 2022;158:112086. https://doi.org/10.1016/j.rser.2022.112086.
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- Langer J, Quist J, Blok K. Recent progress in the economics of ocean thermal energy conversion: Critical review and research agenda. Renew Sustain Energy Rev 2020;130:109960. https://doi.org/10.1016/j.rser.2020.109960.

Conference papers

- Langer J, Lombardi F, Pfenninger S, Quist J, Blok K. The role of inter-island power transmission for full decarbonisation pathways of archipelagic island states: first results for Indonesia, presented at The 36th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems, 25–30 June, 2023, Las Palmas de Gran Canaria, Spain.
- Langer J, Quist J, Blok K. 282 Harnessing the economic potential of ocean thermal energy conversion in Indonesia with upscaling scenarios, in: Schnitzer, H., Braunegg, S. (Eds.), 20th EUROPEAN ROUNDTABLE ON SUSTAINABLE CONSUMPTION AND PRODUCTION 2021. Graz, pp. 261–278. https://doi.org/10.3217/978-3-85125-842-4-37

Impact of PhD research and awards

General

- Presentation at webinar organised by Indonesia's National Research and Innovation Agency BRIN. The webinar was attended by senior staff of PLN, ESDM, and BRIN, amongst others
- RET review paper cited by International Energy Agency [380]

OTEC

- Cited by African Development Bank [381] and International Energy Agency [382]
- Interviewed by the National Renewable Energy Laboratory (NREL)
- Work presented to the Indonesian trade mission by the Dutch Marine Energy Centre (DMEC)
- Research collaboration with Lappeenranta-Lahti University of Technology (LUT)

Offshore wind

- Interest for further collaboration by BRIN and ITB
- Invited by Energy Academy Indonesia (ECADIN) to give capacity building workshop to PT Pertamina, Indonesia's state-owned oil and natural gas company
- Contact established with Pondera, who signed a MoU with PT Pertamina for the development of Indonesia's first offshore wind farm

Onshore wind

- Used by Danish Energy Agency for capacity building at PLN and feasibility study in Aceh

Solar PV paper

- Invited to the Community of Practice by Gesellschaft für Internationale Zusammenarbeit (GIZ)
- Considered for feasibility study in Sulawesi by GIZ

Awards

- 1st place Best Student Paper Award at the European Roundtable on Sustainable Consumption and Production 2021 (ERSCP2021), 10th September 2021, Graz, Austria
- Recipient of Saga University Private Fund 2021
- 3rd place TU Delft Wind Energy Institute Best Paper Award, 16th March 2022, Delft, The Netherlands
- 2nd place Best Poster Award at the International Conference on Ocean Energy 2022, 18th – 20th October 2022, Donostia / San Sebastián, Spain
- Winner Best Poster Award at ETH Summer School on Energy Technology, Policy, and Politics 2023, 27th August – 1st September 2023, Monte Verità, Ascona, Switzerland

Curriculum vitae

Jannis Klaus August Langer was born on 24 March 1994 in Tirschenreuth, Germany. He obtained his Bachelor of Engineering (BEng) in Mechanical Engineering in 2016 from Ostbayerische Technische Hochschule (OTH) Regensburg, Germany. For his bachelor thesis, he conducted a fault analysis and optimisation of the exhaust gas extraction system at the Technischer Überwachungsverein (TÜV, *Technical Inspection Association*) site in Obertraubling, Germany. The concepts developed during the Bachelor thesis were implemented and operate to this day.

In 2018, Jannis obtained his Master of Science (MSc) in Sustainable Energy Technology from Delft University of Technology, The Netherlands. His master thesis was about the global technical and economic potential of *Ocean Thermal Energy Conversion* (OTEC), which sparked his passion and interest in ocean energies.

From 2018 until 2020, Jannis worked as a project developer and consultant for GreenCycle Umweltmanagement GmbH, which is part of Schwarz Group (Lidl, Kaufland). There, he promoted and coordinated the implementation of rooftop solar photovoltaic, Lithium-ion battery storage, and electric vehicle charging stations. Moreover, he was the lead researcher for the living labs project WindNODE and developed concepts for retail-specific demand-side flexibility options, e.g. from freezers, coolers, and forklifts. During that period, Jannis used his free time to turn parts of his and other master students' theses on OTEC's economic potential into peer-reviewed journal articles.

Since October 2020, Jannis works as a PhD Candidate at Delft University of Technology. His dissertation addresses the spatially and temporally resolved technical and economic potential of renewables in Indonesia, with a special focus on OTEC, and how these renewables can be integrated into the power system for full decarbonisation.

In his personal life, Jannis is passionate about his house plants, cooking (especially pizza), and enjoying coffee at the countless excellent cafés in Den Haag, where he currently resides.