Powering Indonesia's Growth

A More Electrified, More Renewable Economy With Solar At Its Core

Prepared by

The Institute for Development of Economics and Finance (INDEF)

The Institute for Essential Services Reform (IESR)

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In Strategic Collaboration With

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Forewords

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Indonesia has an immense renewable resource base, from solar irradiation across the archipelago to the world's largest geothermal potential and substantial hydropower. Yet this potential remains untapped. Meanwhile, Indonesia will need more electricity as our economy grows, industry expands and transport, households and sectors such as data centres become electrified.

This report is important because it shows that the energy transition can support Indonesia's growth. It finds that electricity demand could grow by around 7 percent annually, while a more electrified economy supplied by renewables could strengthen industrial competitiveness, reduce fuel imports and lower power-system costs. Renewables should therefore be viewed not simply as an environmental objective, but as critical industrial infrastructure.

For APLSI, the priority is to build a power system that remains reliable, affordable, secure and progressively cleaner. Solar will play an increasingly important role, alongside storage and stronger grids, while geothermal, hydro, gas and eventually nuclear can support system reliability. The Government's 100 GW solar programme provides direction, but ambition must now be translated into bankable projects.

The private sector is ready to invest. What we need is a clear and predictable framework: competitive procurement, reasonable tariffs and risk-adjusted returns, land and grid access, efficient permitting, appropriate risk allocation and long-term regulatory certainty. Renewable electricity exports can also provide an early catalyst, bringing investment, foreign exchange and scale to Indonesia's renewable supply chain.

Our expectation is straightforward: We, the Government, PLN and industry must work together to turn targets into projects and projects into competitive electricity. If we get the framework right, Indonesia's energy transition can become not a burden on growth, but one of its engines.

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Fabby Tumiwa

CEO, IESR

Indonesia's next phase of economic growth depends on a power system that is affordable, reliable and clean. IESR has long argued that the energy transition is not a burden on development, but a condition for competitiveness, and support 8 percents economic growth goal.

This report strengthens that case: electrification could lift electricity demand growth to around 7 percent per year, and a least-cost mix built around solar and storage could meet that demand at 5 to 15 percent lower total system cost by 2035, without adding new coal or gas plants.

This should change the policy debate. The central question is no longer whether Indonesia can afford a renewable power system, but whether policy, regulation and investment can move fast enough to build it. The government's 100 GW solar PV programme sets the right level of ambition; it now needs an implementation framework that makes large-scale solar, storage and grid expansion bankable and timely. The priorities are practical and urgent: secure suitable land, streamline permitting, accelerate grid connection, improve procurement, and lower financing costs. The modelling shows the destination is within reach; policy must now turn evidence into installed capacity.

Lord Adair Turner

Co-chair, Energy Transitions Commission

Across the world the economics of clean power have changed faster than almost anyone predicted: Over the past three years the cost of solar modules and batteries has roughly halved, so every dollar of investment now buys twice as much clean electricity. Across the world's sun belt, solar paired with storage is becoming the cheapest source of new power.

Indonesia sits squarely in that sun belt, with significant solar irradiation across its geography. Yet solar generation costs in Indonesia remain high and unpredictable, spanning 5 to 10 cents per kilowatt-hour depending on the project, against around 3 cents in India. Solar deployment is held back not by the resource but by the cost of land, grid connection and finance. This report shows that those costs can fall by 30 to 50 percent by 2035, bringing Indonesian solar within reach of other leading countries.

The transition to a more renewable power system that supplies a more electrified economy is an economic and development opportunity as much as, if not more than, a climate one. Specifically for Indonesia, the two opportunities point the same way: the least-cost development path for the power system is also the lower-carbon one, avoiding emissions and clearing the air in fast-growing cities. The evidence from India, China and other early movers is that costs fall fastest where deployment is quickest. Scale is the mechanism, for cost and emissions alike.

Indonesia has set an ambitious course with its 100 GW solar programme. The opportunity now is to get Indonesia on the path to delivering on low-cost solar: to remove the barriers on land, grid and financing that keep costs high, and unleash the power of scale. The prize is a cheaper, cleaner, more secure economy.

Dr Fadhil Hasan

Founder and President Commissioner, INDEF

Indonesia's ambition to grow at 8 percent a year is central to the Indonesia Emas 2045 vision. At the core of this 8% growth target, a question of productivity and structural transformation remains: How can Indonesia move into higher-value industries and build more resilient sources of prosperity? Energy policy sits at the centre of that question, and this report explains why.

Our dependence on imported oil is a structural weakness. As INDEF's own analysis has shown, every dollar on the oil price widens the fiscal deficit. So long as fossil fuels dominate our energy structure, global price volatility will keep transmitting risk into the budget, into inflation, and into the cost of doing business.

A more electrified economy, supplied by more renewable power, addresses that weakness at its source and provides a pathway to integrate industrial manufacturing and the power sector as a new growth engine. The report quantifies the gains: lower import bills, reduced subsidy pressure, new investment, and industries better placed to compete as trading partners begin to price the carbon.

The economic case for modernising the power sector is therefore clear. Reliable, affordable, low-carbon electricity is a precondition for the industrial competitiveness Indonesia needs. The task now is to align energy policy with the 8 percent growth vision, and to treat the transition as an engine of long-term growth rather than a cost to be managed.

Endorsements

<< PLACEHOLDER>>

About

INDEF | GTI GREEN TRANSITION INITIATIVE

The Institute for Development of Economics and Finance (INDEF) is an independent and autonomous policy research institute established in Jakarta in August 1995, focusing on economic and financial policy analysis to inform public debate and support better policymaking in Indonesia. Building on this mandate, INDEF initiates the Green Transition Initiative (GTI) as an international platform to embed climate and clean energy into core growth and development strategies, positioning the green transition as a new engine for investment, productivity, and inclusive economic transformation. Our work spans key areas including energy transition, climate policy, carbon markets, green industrialisation, and sustainable finance, supporting evidence-based policymaking and real-world impact across government, industry, and civil society

IESR Institute for Essential Services Reform

The Institute for Essential Services Reform (IESR) is an independent think tank that accelerates Indonesia's energy transition through evidence-based research, policy advocacy, and cross-sector collaboration. IESR translates technical analysis and modelling, including studies of pathways to net-zero emissions by 2050, into actionable policy recommendations. Through capacity building and stakeholder collaboration, IESR promotes a clean, technically feasible, socially just, and economically resilient energy system.

Energy Transitions Commission

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C. The ETC is co-chaired by Lord Adair Turner and Jules Kortenhorst. The ETC team is led by Ita Kettleborough (Director), and Mike Hemsley (Deputy Director). The ETC also delivers regional programmes across key economies including Europe, the United States, China, India, Japan, Canada, Indonesia, Sub-Saharan Africa and Australia, working with local partners to develop country-specific transition pathways, engage policymakers, and translate global insights into actionable national strategies.

SYSTEMIQ

Systemiq is a system-change company founded in 2016 to accelerate the achievement of the Sustainable Development Goals and the Paris Agreement by transforming the markets and business models that underpin society. A certified B Corp, Systemiq partners with businesses, policymakers, investors, and civil society organizations to reimagine and reshape five key systems—energy, nature and food, materials and circularity, urban areas (the built environment), and sustainable finance—in order to drive the transition to a sustainable and inclusive economy. Combining strategic advisory with high-impact, on-the-ground implementation, Systemiq operates globally with offices in Brazil, France, Germany, Indonesia, the Netherlands, the United Kingdom, and Nairobi.

List of Abbrevations

Abbreviation	Full term
ALMM	Approved List of Models and Manufacturers
APLSI	Asosiasi Produsen Listrik Swasta Indonesia (Indonesian Independent Power Producers Association)
ATR	Agraria dan Tata Ruang (Agrarian Affairs and Spatial Planning)
BAU	Business-as-Usual
BESS	Battery Energy Storage System
BKPM	Badan Koordinasi Penanaman Modal (Indonesia Investment Coordinating Board)
BoS	Balance-of-System
BPN	Badan Pertanahan Nasional (National Land Agency)
BUMN	Badan Usaha Milik Negara (State-Owned Enterprise)
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined Cycle Gas Turbine
CFPP	Coal-Fired Power Plant
DMO	Domestic Market Obligation
DPO	Domestic Price Obligation
EAF	Electric Arc Furnace
EPC	Engineering, Procurement and Construction
EV	Electric Vehicle
FDI	Foreign Direct Investment
FID	Final Investment Decision

Abbreviation	Full term
GDP	Gross Domestic Product
HGBT	Harga Gas Bumi Tertentu (Designated Natural Gas Price)
HPK	Hutan Produksi Konversi (Convertible Production Forest)
IKN	Ibu Kota Nusantara (Indonesia's new capital)
IPP	Independent Power Producer
KLH	Kementerian Lingkungan Hidup (Ministry of Environment)
LCOE	Levelised Cost of Electricity
LCR	Local Content Requirement
MEMR	Ministry of Energy and Mineral Resources
MNRE	Ministry of New and Renewable Energy
MPNT	Maluku, Papua, and Nusa Tenggara
PHS	Pumped Hydro Storage
PLI	Production Linked Incentive
PLN	Perusahaan Listrik Negara (State Electricity Company)
PLTA	Pembangkit Listrik Tenaga Air (large hydropower)
PLTM/PLTMH	Mini/micro hydropower
PLTS	Pembangkit Listrik Tenaga Surya (solar power plant)
PPA	Power Purchase Agreement
RDTR	Rencana Detail Tata Ruang (Detailed Spatial Plan)
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
REZ	Renewable Energy Zone
TKDN	Tingkat Komponen Dalam Negeri (Domestic Content Level)
WACC	Weighted Average Cost of Capital



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1

Indonesia's electricity demand will grow significantly, driven by economic growth and electrification of end-uses.

Indonesia's growing economy is underpinned by a significant electricity demand increase, up to 7% per year for the next decade. High Electrification, especially in transport and manufacturing, could add 160 TWh to electricity demand versus Business-as-Usual by 2035, creating a demand pull for large-scale renewables deployment and catapulting Indonesia's electricity demand per capita from ~1,500 to ~2,800 kWh/capita.

2

Solar is the standout renewable opportunity to meet this demand, but its rollout in Indonesia is stuck in a low-volume equilibrium because of low revenues and high costs.

- Solar is the standout renewable opportunity for Indonesia: largest resource potential, fastest to build, and on a steep global cost decline. The 100 GW solar programme makes solar a national priority, signalling an step change in ambition versus current supply build-out plans (RUPTL). Indonesia's solar market is currently stuck in a low-volume equilibrium: economics are weak because scale is absent, and scale is absent because economics are weak.
- Most of Indonesia's utility-scale solar market is currently stuck in a low-volume equilibrium: economics are weak because scale is absent, and scale is absent because economics are weak.
  - Revenues from PLN are constrained by an unlevel playing field with artificially cheap coal-fired power generation (~3.5-5 cts/kWh for existing plants running on price-capped coal)
    Indonesia's solar generation costs are currently well-above leading-market levels and vary a lot (5-10 cts/kWh in Indonesia versus 3 cts/kWh in India) holding back commercial scaling.First utility-scale projects show the underlying economics can work in Indonesia, and a next wave of catalytic projects and targeted interventions can unlock further scale needed.
  - Total solar generation costs can be reduced by 30-50%, to 4-7 cts/kWh by 2035, through targeted interventions on three key elements: component costs, land costs and transmission costs. A well-planned scale-up and improvements in procurement routes will also bring down financing costs, which feed through to all cost elements.
  - Battery storage completes the solar story: as battery costs fall, solar-plus-storage is becoming a cost-competitive alternative to new coal and gas in sunny markets globally. Although Indonesia's current solar-plus-storage cost of around 15 cts/kWh remains well above leading-market levels (such as 4.5 cts for almost round-the-clock solar+BESS in India), it may fall in step with the standalone solar cost reductions above.
  - The first utility-scale solar projects show the underlying economics can work in Indonesia (for example for sites with pre-secured land, or designated national strategic projects) and a next wave of catalytic projects and targeted interventions can unlock further scale needed.

3

Moving towards a more electrified economy and more renewable-power system can contribute around 8-10% of the additional GDP growth Indonesia needs to reach its 8% growth ambition, while improving energy security, affordability and competitiveness.

- **The High Electrification, least-cost scenario delivers around USD 160 billion of additional GDP between 2025-2035 versus BAU,** built from two direct GDP components: around USD 25 billion in additional investment (across the energy system, electrification, clean manufacturing, and new growth sectors enabled by low-carbon power such as data centers) and around USD 125 billion in additional net exports (reduced oil imports and regional electricity exports).
- **Increased electrification and more renewables strengthen Indonesia's energy resilience and reduce import dependence**, reducing oil demand by 22% annually by 2035, leading to savings of USD 60-75 billion in cumulative oil imports. Savings are concentrated in transport, where electrification of two-wheelers, cars, vans, buses, and trucks is increasingly cost-effective.
- **Increased electrification and more renewables can reduce spending on energy subsidies by USD 20 billion over the next decade**, increasing government budget resilience to imported fuel price shocks and freeing up fiscal space for other uses.
- **A more renewable supply mix improves power system affordability** while meeting higher demand. By 2035, total power system costs fall by around 5-15% in the more renewable supply mix versus the RUPTL mix, from ~10 to 8.5 cts/kWh, with no new coal or gas plants needed to satisfy 180 TWh of additional demand.
- **A more renewable supply mix also makes Indonesia more competitive in green industries.** Global markets increasingly reward low-carbon supply (e.g., through CBAM), and countries with cleaner power systems will be better positioned for exports, and more attractive as base for international manufacturers seeking to establish low-carbon supply chains.

4

Capturing these gains requires four coordinated interventions to bring down the cost of solar generation: fast-tracking catalytic (grid-scale) projects, removing barriers to rooftop solar, providing policy support to bring down solar cost components, and designing a phased local content strategy.

- **Catalytic grid-scale solar projects with premium buyers** (electricity exports to neighbouring markets, data centres, first phase of the 100 GW) can anchor early demand at scale, bypassing current revenue hurdles, and generate the bankable precedent that unlocks lower financing costs and supplier capacity build-out.
- **Rooftop solar can be unblocked** by updated quota and permitting regulations, allowing rapid scaling of rooftop capacity and increasing domestic module demand.
- **Targeted policy support on land acquisition and grid connection** brings down the two solar generation cost components that cause the largest cost differential with leading solar markets and can unlock low-cost solar generation for Indonesia and also impact other renewable energy sources such as geothermal and hydropower.
- **A phased local content strategy** balances domestic manufacturing ambitions with cost competitiveness, building the supply base without locking in higher costs that hold back deployment.

The 100 GW solar programme

This report analyses Indonesia's full power system and its impact on economic outcomes. Within the power system, the government's 100 GW solar programme stands out as a critical development. It appears throughout the main report where relevant; this box brings the threads together: what the programme is, why it matters for Indonesia, and what its delivery depends on.

Delivering the 100 GW programme by 2030 is ambitious, but this build-out pace is not unprecedented

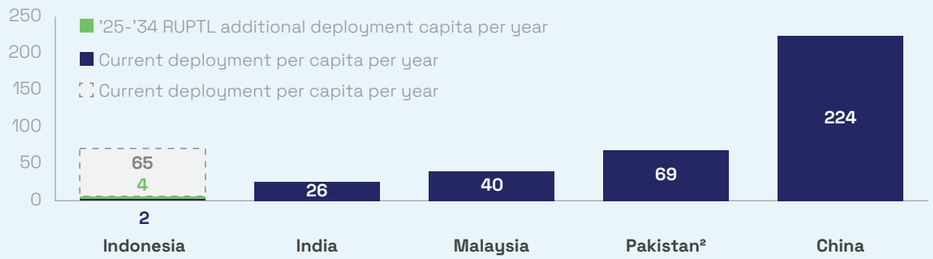
In August 2025, the government set a target of installing 100 GW of solar PV by 2030, spanning off-grid, rooftop, and utility-scale solar. This is a step change. The current national electricity plan (RUPTL) envisages just 17 GW of on-grid, utility-scale solar by 2035, and delivering the 100 GW would come close to doubling Indonesia's entire installed capacity in five years.

At first glance the target looks daunting. But compared against regional peers, the leap is large but not unprecedented [Fig 1]: it would lift Indonesia from a solar PV deployment pace of around 2 MW per million people per year to around 65 MW per million people per year, close to Pakistan's deployment pace over the last two years. The scale is also not unprecedented: India installed 38 GW of solar in 2025 alone and China 315 GW[1]. Pakistan, with a comparable population to Indonesia, installed roughly 27 GW of distributed solar in around two years without any national programme[2].

Figure 1 | Regional peers show much higher solar deployment per year than Indonesia.

Regional Peers Show What Is Achievable Regarding The Deployment Pace Of Solar Capacity

Solar capacity installation per capita per year, MW per million people, 2024/2025[1]



Notes: 1. most recent year available used (2024 for Pakistan, 2025 for all others). No reliable annual installation figure exists. The 17 GW figure reflects panel imports in CY2024. 2. Assumes the 100 GW is realized in 5 years.
Source: Indonesia: Ministry of Energy & Mineral Resources (MEMR) / IESR, reported in pv magazine, February 2026. Pakistan: Ember Chinese solar export data / Wikipedia Solar Power in Pakistan (imports, CY2024); NEPRA State of Industry Report 2024 (net-metered capacity); WRI, "The Perfect Storm Fueling Pakistan's Solar Boom," October 2025. India: Ministry of New and Renewable Energy (MNRE) official data, reported in pv magazine, January 2026. China: National Energy Administration (NEA), reported in pv magazine, January 2026. Population: UN World Population Prospects 2024.

1 PV Magazine (2026) India deploys 37.9 GW of solar in 2025
2 Ember (2026) The solarization of Pakistan's energy economy

One thing does set Indonesia apart from these peers: in none of them, solar had to compete against coal as cheap as Indonesia's. Indonesia caps the price of coal sold to power stations well below the market price, which keeps coal-fired electricity artificially cheap and sets a low price for solar to undercut. Even with artificially cheap coal, the cost gap with solar is closing fast: India can already build new utility-scale solar farms that generate electricity more cheaply than it costs to keep running Indonesia's existing coal plants on price-capped coal.

What makes all of this possible is one of the fastest cost declines in industrial history. Since 2010, the cost of solar modules has fallen by around 97%, and the installed cost of utility-scale batteries by around 93%[3]. Solar is now the cheapest source of new electricity in most of the world, and batteries have become cheap enough to store that power for use after dark.

That combination is transformational for a sunbelt country like Indonesia. Solar produces most of its power in the middle of the day, but demand peaks in the evening, when families come home, switch on lights, and run air conditioning. Batteries bridge that gap: they can store cheap daytime solar for use at night, keeping air conditioners and appliances running long after the sun has set. This is why solar paired with storage is the real opportunity. The Energy Transitions Commission finds that for sunbelt countries, the combined collapse in solar and battery costs now makes it possible to run power systems on solar and wind at costs at or below today's fossil-fuelled systems, needing only to balance day and night rather than the harder task of balancing across seasons that colder, cloudier countries face[4].

Increased electrification and storage can absorb new electrons

Solar at this scale gains further momentum when demand grows to absorb it. That demand is coming: as Indonesia's economy grows and electrifies, its need for electricity can climb steeply, ensuring new solar-powered electrons can be put to use. In a high electrification scenario, in which transport and industry electrify faster, households increasingly use air conditioning and electric cooking, and new electricity-intensive sectors (such as power exports and data centers) grow, Indonesia could need around 160 TWh more electricity in 2035 than it would under a business-as-usual demand trajectory.

Scaling solar can meet that additional demand. When Indonesia's power system is expanded to meet this higher demand at the lowest possible cost, it takes on around 70 GW of utility-scale solar by 2035, and up to 114 GW if solar costs fall faster and the price cap on coal is removed [Figure 2]. Add the rooftop and captive solar going up on homes and factories, and the total can even reach the 100 GW ambition by 2030. The scale is well-calibrated: a system designed to keep costs down would build close to this much solar anyway.

What that solar needs to be dependable is storage. Solar stops generating at sunset, just as evening demand rises, so batteries are needed to store cheap daytime power and release it after dark. The same modelling shows Indonesia will need on the order of 55 to 70 GWh of storage by 2035 to keep pace with this solar deployment. These volumes are achievable, but they will not appear on their own: storage has to be deployed deliberately, in step with solar.

3 Irena (2025) Renewable Power Generation Costs in 2024
4 ETC (2025) Power Systems Transformation

Figure 2 | Solar generation capacity and storage volumes deployed in least-cost modelling for scenario C and two sensitivity scenarios.



Source: IESR analysis. Notes: . 1. BESS and PHS. For BESS, assuming a 4-hour storage duration. 2. Scenario C assumes Solar LCOE of 4.5-9 cts/kWh in 2030 and 4-7 cts/kWh in 2035. 3. Sensitivity 1 assumes Solar LCOE of 4-7 cts/kWh in 2030 and 3.5-5 cts/kWh in 2035. 4. Sensitivity 2 assumes Solar costs reach 3.7 cts/kWh in 2027 (India's current level, adjusted for Indonesia's lower capacity factor. 5. Sensitivity 2 assumes Coal generation costs increase by 30%, to 4.5 cts/kWh for existing assets and 9 cts/kWh for new assets.

The 100 GW programme can strengthen resilience and unlock green growth

Cost is not the only reason countries are racing to build solar. The cost declines have been visible for a decade, yet the countries moving fastest are those where solar and storage do more than lower bills: they strengthen energy security, increase access to power, clean the air, and cut emissions, all at once. Those are precisely the gains on offer for Indonesia. The value of the 100 GW programme is not the panels themselves, but the resilience and green growth those electrons can deliver.

In addition to reducing emissions, cheap, abundant, home-grown solar power can strengthen Indonesia in six ways:

- **Powering a new economy.** Low-cost clean power can anchor high-value industries in Indonesia, from data centres and downstream processing to green metals, and extend reliable electricity to communities still without it.
- **Lowering power costs.** A more renewable supply mix could cut total power-system costs by around 5 to 15% by 2035, with no new coal or gas plants needed to meet rising demand.
- **Reaching every island.** Solar and batteries can be built close to where power is needed, in a country too vast and fragmented to connect through one grid alone. Distributed solar brings generation to communities and industries across the archipelago, easing the strain on transmission and reducing reliance on a single, centralised system.
- **Strengthening energy security.** Solar power is generated at home, so every diesel generator or oil-burning engine it replaces cuts Indonesia's need for imported fuel. Scaling renewables and electrification could save the country tens of billions of dollars in oil imports over the coming decade, money that stays in the economy rather than flowing overseas.
- **Improving competitiveness.** Global markets increasingly reward low-carbon supply, through carbon border charges and buyer demands on the carbon intensity of electricity. Cleaner power makes Indonesia a more attractive base for manufacturers building resilient, low-carbon supply chains.
- **Cleaner air, better health.** A more electrified, more renewable system reduces air pollution both where electricity is consumed, for instance when an electric motorbike replaces a petrol one, and where it is generated, when renewables replace coal. Cleaner air means better health across Indonesia's cities.

The scale is deliverable, now is the time to accelerate delivery

The scale of 100 GW is deliverable. Where Indonesia stands today, reaching it by 2030 is a stretch, but that is a reason to accelerate, not to continue debating timelines. What matters is turning the ambition into projects on the ground, and three things will decide how fast that happens.

First, build where it is easiest to win. The fastest way to build momentum is to start where the economics already work. Premium buyers, such as data centres and international manufacturers that want clean power, are willing to pay for it now, and can anchor the next wave of large-scale projects. Concentrating solar in renewable energy zones, where industrial demand meets with good irradiation, available land and grid access, lets developers build quickly and turns these first deals into a pipeline[5]. Solar and batteries can also replace expensive diesel generators in remote areas today, cutting fuel costs immediately[6]. Alongside this, targeted action to bring

5 Systemiq (2026) Advancing Indonesia's Industrial Energy Transition: The role of Renewable Energy Zones
6 IESR (2026) Solar Archipelago: Indonesia's 100 GW Leap to Energy Sovereignty

down Indonesia's two biggest solar cost premiums, land and grid connection, would lower costs across every project that follows.

Second, build demand in step with supply. Solar can both meet Indonesia's fast-growing electricity needs and replace coal generation to cut emissions. In the near term, the quickest way to absorb a large solar build-out is to grow demand alongside it: policy that accelerates the electrification of transport and industry, alongside new demand from data centres and rural electrification, keeps consumption rising in step with generation, so the new solar has a ready market to serve.

Third, scale storage alongside solar. Storage is what turns daytime solar into power the country can rely on after dark. Deploying batteries in step with generation keeps the system stable and makes sure cheap solar is available when demand peaks in the evening. Peer countries have paired renewables with batteries deliberately: in China, provincial co-location mandates from 2017 onwards required new solar and wind projects to install a share of storage, a policy that helped cut curtailment from over 17% in 2016 to below 5% and pushed installed battery capacity past 74 GW by 2024[7]. India has taken a complementary route through funding up to 30-40% of capex for battery storage projects, alongside hybrid (storage + renewables) tenders that now account for around half of all renewable auctions[8].

None of this rests on government alone. Developers, investors, industry, and the state each have work to do, and the pieces reinforce each other: rising demand pulls in solar and storage, and cheaper solar makes electrifying more attractive still, feeding demand further. Levelling the playing field between solar and Indonesia's price-capped coal would accelerate solar deployment further, though that is a longer-term shift rather than a fast intervention. What is not in doubt is the destination. The prize of the 100 GW is not the panels, but the cheaper power, increased energy security, and new industries these new electrons unlock, and the sooner Indonesia scales solar, the sooner it captures these benefits.

7 Ember (2025) From scale to system: navigating the next phase of China's battery storage
8 IEEFA/JMK Research (2025) The Standalone Energy Storage Market in India

Introduction

Indonesia is targeting a step change in economic growth: from around 5% per year today to 8% by 2029, as per the Indonesia Emas 2045 vision. Achieving this implies drastic growth in electricity supply: rising incomes, industrial downstreaming, and new electricity-intensive sectors will significantly increase electricity demand over the next decade, with much more growth expected for the decades to come as the economy grows and electrifies.

Indonesia's current power system is heavily reliant on fossil fuels, with around 85% of 2025 generation coming from coal, gas and diesel. Renewables currently make up just 15% of generation, with the bulk of that share coming from a small number of legacy hydropower and geothermal plants. Solar and wind, which have driven most of the global renewable build-out in recent years, together account for less than 1% of Indonesia's electricity generation today. [9]

Indonesia's current power system is heavily reliant on fossil fuels, with around 80% of 2025 generation coming from coal gas and diesel.

There is a growing opportunity to change this. Indonesia holds a significant renewable energy resource base, with the potential to underpin decades of economic growth on domestic, fuelless electricity. The country holds significant solar irradiation across the archipelago, the world's largest geothermal potential, and significant hydropower capacity. Solar in particular stands out: IESR analysis suggests it could meet up to 88% of expanded electricity demand by 2060[10]. The conditions for a renewables-led power system are there.

At this point, however, affordability remains a genuine barrier in Indonesia. Under regulated Domestic Market Obligation (DMO) pricing, coal-fired power generation delivers electricity at around 3.5-5 cts/kWh, a cost level Indonesian solar generation cannot yet consistently match at 5-10 cts/kWh. While some first-mover solar projects have materialised in locations where all conditions where favourable, these projects have proven difficult to replicate in large volumes. The result is a low-volume equilibrium: solar project economics are weak because scale is absent, and scale is absent because economics are weak.

There is a path to break through this equilibrium, and regional peers are already showing what it looks like [Figure 1]. India has reached around 3 cts/kWh for electricity delivered through solar, with around 4.5 cts/kWh for solar paired with batteries on an almost round-the-clock

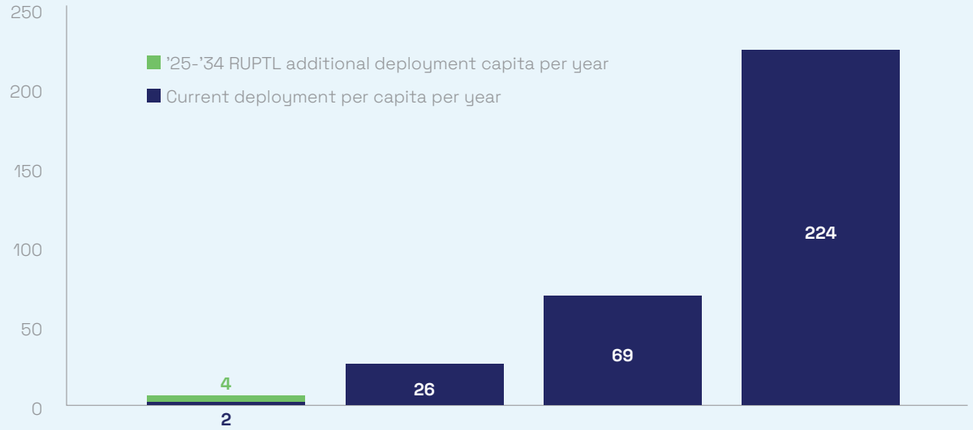
9 ESDM (2026) Handbook Of Energy & Economic Statistics Of Indonesia 2025
10 IESR (2021), Deep decarbonization of Indonesia's energy system

basis[11], and installed 38 GW of solar in 2025 alone[12]. Pakistan, with a comparable population and lower income per capita, [13]installed 27 GW of distributed solar in just two years, without a national programme.[14]

Figure 1 | Regional peers show much higher solar deployment per year than Indonesia.

Regional Peers Show What Is Achievable Regarding the Deployment Pace of Solar Capacity

Solar capacity installation per capita per year, MW per million people, 2024/2025[1]



Notes: 1. most recent year available used (2024 for Pakistan, 2025 for all others). No reliable annual installation figure exists. The 17 GW figure reflects panel imports in CY2024. 2. Assumes the 100 GW is realized in 5 years.
Source: Indonesia: Ministry of Energy & Mineral Resources (MEMR) / IESR, reported in pv magazine, February 2026. Pakistan: Ember Chinese solar export data / Wikipedia Solar Power in Pakistan (imports, CY2024); NEPRA State of Industry Report 2024 (net-metered capacity); WRI, "The Perfect Storm Fueling Pakistan's Solar Boom," October 2025. India: Ministry of New and Renewable Energy (MNRE) official data, reported in pv magazine, January 2026. China: National Energy Administration (NEA), reported in pv magazine, January 2026. Population: UN World Population Prospects 2024.

The window for change is opening. Globally, solar PV module costs have fallen by around 20% per year over the past decade, and battery costs by around 16% per year, faster than any prior projection[15]. Solar is now the cheapest source of new electricity across most sunny climates, with global benchmark LCOEs around 4 cts/kWh[16]. Combining solar with batteries is

11 Solar + BESS systems providing 75-85% annual availability
12 PV Magazine (2026) India deploys 37.9 GW of solar in 2025
13
14 Ember (2026) The solarization of Pakistan's energy economy
15 BNEF (2025) Lithium-Ion battery price survey. December 2025
16 BNEF (2026) Battery Storage Costs Hit Record Lows as Costs of Other Clean Power Technologies Increased: BloombergNEF

also increasingly affordable, at 5-8 cts/kWh across sunny climates[17]. Electrification amplifies this advantage: electrified technologies are structurally more efficient than their fossil-fuel equivalents, and the enabling technologies (batteries, electric motors, and heat pumps) keep getting cheaper as they scale. electrified technologies are structurally more efficient than their fossil-fuel equivalents, and the enabling technologies (batteries, electric motors, and heat pumps) keep getting cheaper as they scale.

The moment for action

Three factors make this a decisive moment for action. First, energy resilience has become a live fiscal priority. The 2026 Iran conflict pushed oil above USD 100 per barrel against a state budget assumption of USD 70, exposing Indonesia's structural vulnerability as a net oil importer. Each additional dollar in the oil price adds approximately IDR 6.8 trillion to government spending, with energy subsidies already consuming over 5% of the state budget[18]. Reducing oil dependence through electrification (particularly in transport, where oil consumption is concentrated) and renewable supply (by replacing diesel generators) directly addresses this fiscal exposure.

Second, government ambition is accelerating. The 100 GW solar programme announced in 2025 represents a step change from the 17 GW targeted under the previous Power Development Plan (Rencana Usaha Penyediaan Tenaga Listrik, or RUPTL). To make this timeline, it is pivotal that solar generation costs are brought down, to compete with existing coal-fired power generation. This will require structural changes to both market structure and regulations (such as the solar rooftop quota system), and a concerted effort to grow electricity demand hand-in-hand with supply.

Third, several time-bound opportunities are happening now. Renewable electricity exports to Singapore and anchor offtake from international data centre operators are live demand sources with buyers willing to pay a premium for clean power, overcoming existing PLN revenue barriers. These can anchor catalytic renewable projects and resolve existing barriers. If Indonesia does not act quickly, these opportunities will move to competing markets.

What this report does

This report examines whether higher electrification combined with a more renewable electricity supply could strengthen Indonesia's economic growth prospects. It is structured as follows:

Chapter 1

examines how electricity demand could evolve under a Business-as-Usual scenario and a High Electrification scenario. Demand grows by around 5% per year in BAU and 7% in High Electrification, due to accelerated electrification of transport, industry and residential demand.

17 Irena (2026) 24/7 Renewables: the economics of firm solar and wind; Modelled firm LCOE for solar and battery setups with 95% availability
18 IDN Financials (2026), Oil hits USD 100, Indonesia to keep fuel subsidies through 2026.

Chapter 2

shows that despite a large resource base, Indonesia is lagging on renewables deployment and identifies the structural barriers preventing scale.

Chapter 3

diagnoses why Indonesia's solar costs sit above leading-market levels and sets out how each cost component can come down. With targeted action, Indonesia's solar LCOE could fall by 30-50% by 2035, approaching the levels already achieved in leading markets.

Chapter 4

assesses how supply can evolve to meet demand. It compares the current RUPTL with a least-cost supply mix featuring greater renewable deployment. A more renewables-led supply mix delivers around 5-15% lower total system costs by 2035 than the current RUPTL pathway, while satisfying more electricity demand.

Chapter 5

quantifies the economic implications of electrifying the economy and scaling renewables: reduced fossil fuel imports and subsidies, increased investment and new growth sectors enabled by clean power, and improved (export) competitiveness.

Chapter 6

sets out the policy interventions required to deliver a more electrified, more renewable economy, focusing on the interventions needed to bring solar costs down and sector measures that can accelerate electrification.

Taken together, these chapters make the case that a shift to a more electrified economy, supplied by a more renewable power system is not only a climate objective: it is an economic one. The evidence in this report suggests Indonesia can build the power system needed to sustain faster growth, at lower cost, while improving competitiveness and resilience, if the right actions are taken now.





Chapter 1

Indonesia's electricity demand will grow materially over the next decade

Indonesia's economic growth ambitions are entering a decisive decade, with the government targeting an increase from ~5% to 8% annual GDP growth by 2029. The government aims to accelerate growth by strengthening industrial competitiveness, focusing on expanding downstream mineral processing and higher-value manufacturing. In emerging economies, periods of faster GDP growth have historically been accompanied by rising electricity demand[19]. If Indonesia succeeds in expanding industry, raising household incomes, and building new digital and manufacturing sectors, electricity demand will increase materially over the next decade.

This chapter examines the scale and drivers of Indonesia's electricity demand growth over the next decade. Section 1.1 sets out Indonesia's economic growth ambitions and how rising incomes and industrial expansion translate into higher electricity demand. Section 1.2 presents the drivers of electricity demand and introduces the two demand scenarios used in the report: a Business-as-Usual pathway and a High Electrification pathway. Sections 1.3 and 1.4 set out the demand outlook under each scenario in detail. Section 1.5 examines how demand growth is distributed across regions and across captive versus on-grid supply. Section 1.6 closes with what these trajectories imply for the scale of power system expansion required.

1.1
Indonesia's growth ambitions

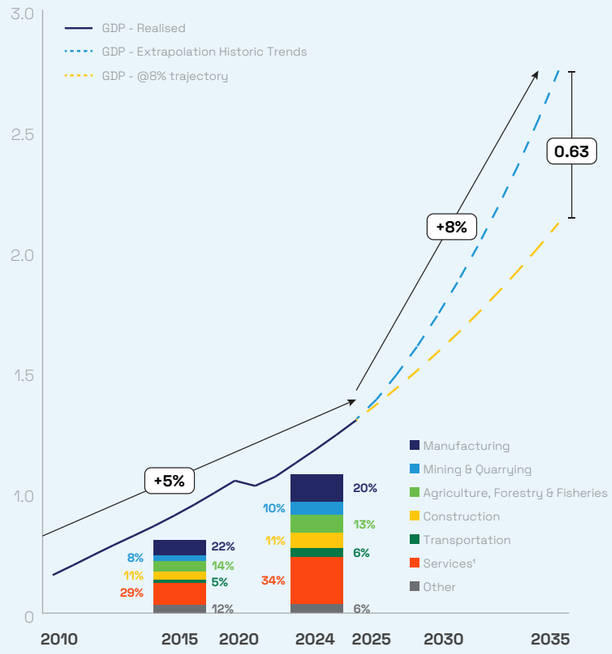
Indonesia has set an ambitious economic growth target as part of its long-term development strategy. The government aims to increase annual GDP growth from around **5% today to 8% by 2029,** in line with the *Indonesia Emas* 2045 vision [Figure 2] Achieving this target would represent a step-change compared with the country's current economic trajectory, which has resulted in ~5% annual GDP growth for the past 10 years.



19 IEA (2026), Electricity 2026: Analysis and forecast to 2030

Figure 2 | Indonesia has articulated a clear ambition to accelerate economic growth towards ~8% per year by 2028-2029, a step-change vs historic growth.

Historic and forecast GDP, Trillion USD (constant 2015)



Relevant Policies

National Vision: Indonesia Emas 2045 (RPJPN 2025-2045)
Industrialization as the central driver for long-term economic transformation, with manufacturing's GDP share rising from 22% to 28% by 2045.

Strengthening the foundation (RPJMN 2025-2029)
Focuses on downstreaming, priority industries, industrial zones, and export-oriented manufacturing to strengthen industry as the primary growth engine.

Industrial transformation as the pathway to 8% growth
Indonesia positions manufacturing-led growth as essential for lifting productivity and enabling Indonesia to achieve 8% sustainable growth.

Notes: 1. Services includes wholesale, trading, repair of vehicles, accommodation and food service, IT, Telco, financial and insurance, real estate and business activities.
Source: BPS: Quarterly Growth Domestic Product 2020-2024 and 2021-2025

As Figure 2 demonstrates, services make up the largest share of Indonesia's GDP today, at 34%. Manufacturing currently accounts for around 20% of GDP, down from close to 30% in the early 2000s and below levels seen in several fast-growing Asian economies during their industrialisation phases[20,21]. The decline in manufacturing's share of GDP in Indonesia reflects several structural factors: commodity-led growth (e.g., nickel, palm oil, coal) that crowded out manufacturing investment, a loss of manufacturing competitiveness relative to regional peers such as Vietnam, China, and Thailand, and an early shift toward lower-productivity service sectors.

Indonesia's current strategy for achieving higher economic growth is focused on reversing this trend, by expanding higher-value manufacturing and downstream processing, particularly

20 World Bank (2024), World Development Indicators
21 e.g. South Korea ~29–30% of GDP in the 1980s–1990s, China ~30–32% during the 2000s, and Taiwan ~28–30% during its peak industrial expansion)

in resource-based sectors such as nickel, aluminium, and other critical minerals. A stronger industrial base would increase manufacturing's contribution to GDP, increase manufacturing exports and support higher-value economic activity.

Independent of the exact growth rate ultimately achieved, the target signals a clear policy direction: Indonesia aims to expand its industrial base, increase productivity, and strengthen its position in global manufacturing and commodity value chains.



1.2 Drivers of electricity demand and future scenarios

Rising incomes and industrial expansion will materially increase Indonesia's energy – and particularly electricity demand – over the next decade.

As economies develop, energy and electricity use per capita typically rise alongside incomes, reflecting higher household consumption, expanding services and growing industrial activity. For example, during China's rapid industrialisation between 2000 and 2015, electricity use per capita grew from around 1,000 kWh to 4,000 kWh per person, equivalent to around 10% annual growth, roughly in step with GDP growth of almost 10% per year over the same period; consumption has since risen further to over 7,500 kWh per person[22]. Vietnam's electricity use per capita grew even faster over the same period, from around 300 kWh to 1,600 kWh per person, equivalent to around 12% annual growth, outpacing average GDP growth of around 6.5% per year, and now stands at around 2,700 kWh per person[2324]. By comparison, Indonesia's electricity use remains low today at around 1,500 kWh per person[25] suggesting significant potential for further growth as incomes and industrial activity expand.

In Indonesia, rising incomes are expected to increase total energy demand across the residential, commercial, and transport sectors. Higher appliance ownership and increased air conditioning use will raise electricity consumption [Figure 3]. Commercial electricity demand

22 Ember (2026) Global Electricity Review 2026
23 World Bank (2026) Electric Power Consumption (kWh per Capita),
24 World Bank (2026) GDP Growth (Annual %)
25 Systemiq analysis based on data from Databoks (2025) and ESDM (2025)

will also increase as new digital infrastructure expands, particularly data centres, which are emerging as a fast-growing source of electricity consumption. At the same time, growing passenger and freight traffic will increase transport energy demand.

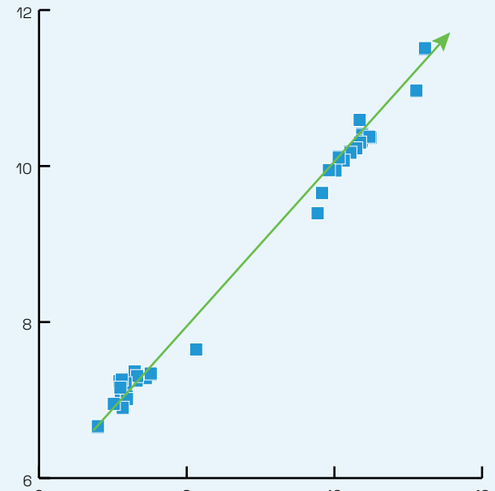
Figure 3 | As GDP per capita and incomes grow, residential electricity demand will increase, mostly driven by cooling (AC) demand.

Higher-income regions already see higher residential electricity consumption

Mean Electricity Consumption vs. GDP per Capita for regions in Indonesia

Log scales, 2014-2022

Mean electricity consumption per household

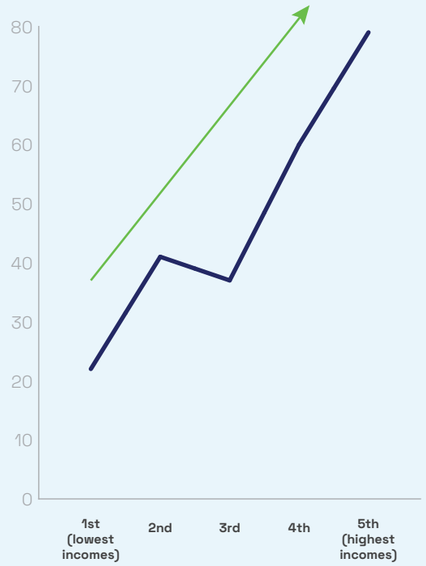


AC uptake will increase as incomes increase

Est. AC penetration by Income Quintile In East Asia And Pacific

% Penetration vs income quintile

% Penetration



Source: IEA (2025) Staying cool without overheating the energy system; Basconcillo et al. (2023) GMM Approach to Residential Electricity Consumption in Indonesia

Industrial expansion will also increase electricity demand in two ways. First, expanding industrial activity across sectors such as manufacturing, mining, and metals processing will raise overall energy use. Second, the downstreaming strategy shifts activity from mining and exporting raw materials toward more energy-intensive processing and materials production.

Key industrial growth sectors include aluminium and nickel processing, iron and steel production, battery manufacturing, and data centres, all of which are energy intensive and will contribute significantly to rising industrial electricity demand [Figure 4]. Government projections point to particularly rapid expansion in aluminium production, projected to grow by around 30% per year over the next decade, while nickel output is projected to increase more gradually from 2.4 Mt to 2.8 Mt per year, maintaining Indonesia's position as the world's largest nickel producer.

Figure 4 | The manufacturing sector is projected to grow materially over the next decade.

POWER DEMAND | Industrial Growth is Excepted to Play a Central Role in Delivering Economic Growth

Projected Production Output of Selected Manufacturing Sectors	2025	2035	2025-2035 CAGR	Current GDP Contribution[7]
in Mt			in %	in %
Iron & Steel[1]	13	19	+4%	1.1%
Nickel[2]	2.4	2.8	+2%	
Aluminium[3]	0.2	3.1	+30%	
Copper[4]	0.8	0.8	0%	
Minerals[5]	81	75	-1%	0.5%
Chemicals	10	14	+3%	1.8%
Pulp & Paper	23	25	+1%	0.6%
Textiles	7	11	+5%	1.0%
Food & Beverage[6]	116	130	+1%	7.1%

Notes: 1) Based on Ministry of Industry (Kemenperin) growth projections; 2) Based on existing capacity, derived from CREA (2024); 3) Aluminium increase is based on pipeline projects in Kalimantan Aluminium Industry (2027 COD), Hua Chin Indonesia (2025 COD), INALUM extension (2028 COD), and Bintan Electrolytic (2028 COD); Sources: Petromindo, GAIKINDO, AISI, EMBER, Pusat Industri Hijau (PIH), BPS, IESR-Systemiq Analysis. 5) Minerals consists of cement, glass and ceramics. Growth based on PIH, Housing & Settlement Statistics. 6) Food & Beverage includes sugar & palm oil production, the largest subsectors within F&B.7) Based on BPS (for 2025, preliminary data). Note: total manufacturing contribution in 2025 was 19.1%. Of the sectors not included here, the only sectors contribution >1% are: manufacture of coal products, oil and gas refineries (1.9%), manufacture of fabricated metal products (1.6%), manufacture of transport equipment (1.3%).

Taken together, these trends point to **materially higher electricity demand over the next decade.** The scale of that increase will depend not only on how fast the economy grows, but also on how strongly households, transport, industry, and new electricity-intensive sectors shift toward electrified technologies. To capture this uncertainty, we develop two scenarios for the evolution of demand [Figure 5].

Figure 5 | Summary of Business-as-Usual and High Electrification demand scenarios.

Summary of Assumptions for Two Electricity Demand Scenario

	Business-As-Usual (BAU) Scenario	High Electrification Scenario
Parameter	Continuation of historic trends, demand is aligned with projected population and economic growth	Higher electricity demand through electrification and growth of renewables-anchored sectors

Sectoral drivers of electricity demand growth	• Demand for households and commercial in line with RUPTL's forecasts (annual population growth of 0.6%; annual GDP growth of 5% between '25-'35)
	• **Continued trajectory of residential** AC adoption, to 24% of households to own an AC by 2035 (up from 12% in 2025)
	• **Continued trajectory of EV adoption** (0.8 million EVs and 2 million E2Ws by 2035)
	• Pipeline of new **aluminium** smelters is projected to add ~3 Mt production capacity by 2035.
	• Pipeline of new **nickel** smelters planned, adding 350 kt production capacity by 2035.
	• Pipeline of **data centers**, based on existing pipeline and government target of 2000 MW by 2029
		Same basis growth trajectory as in business-as-usual, with the addition of:
		• Assumes **increased residential electricity demand** (through increased AC adoption, 38% of households to own an AC by 2035, and 8% electrification of cooking by 2035)
		• Accelerated **electrification of cars and motorcycles** (EVs making up 26% of car stock by 2035, E2Ws 37% of 2W fleet) and of heavy duty trucks used in the mining sector (37% electric by 2035)
		• Demand unlocked by **renewables-anchored growth sectors**:
		  ◦ Additional demand from **increased data centers build-out**
		  ◦ Additional **regional power export** to neighbouring markets, growing to 5 GW in the next decade
		• A gradual and partial substitution of captive demand by on-grid demand, growing to ~10% of captive demand connecting to the grid by 2035

Electrification of industry	**No change** - assumed consistent with today's industrial electrification rates	**Increased electrification of industry:** • Increased share of EAF steel production • Shift from oil, gas and coal boilers to heat pumps and e-boilers in food and textile industries • Shift from coal, oil and gas boilers to biomass and e-boilers in pulp & paper

For (sub)sector specific assumptions, please see the accompanying Technical Appendix

The **Business-as-Usual (BAU) scenario** reflects continued growth in electricity demand driven by population and income growth, rising household cooling demand, ongoing uptake of electric vehicles, and the current pipeline of power-intensive industrial sectors such as metal smelting and data centres, while keeping industrial electrification rates stable.

The **High Electrification (HE) scenario** uses the same underlying macroeconomic growth trajectory as in BAU, but tests what higher demand could look like **if electrified technologies scale faster across households, transport, and industry, and potential demand that is anchored to the availability of renewable power, additional demand from data green centres and electricity exports, expands more strongly.** These sectors are assumed to only grow to their full potential if they can access renewable power.

The High Electrification scenario is not just theoretical: it is the global direction of travel. Three reinforcing reasons explain why globally this shift is already underway:

- **Electrified technologies are structurally more energy efficient.** EVs convert over 77% of grid electricity into motion at the wheels, while conventional petrol vehicles convert only 12–30% of energy into motion[26]. Heat pumps are three to five times more energy efficient than fossil-fuel boilers[27]. For Indonesia, IEA and MEMR analysis find that in a more electrified scenario, total household energy bills as a share of disposable income fall by 2030 versus a stated policies scenario, mainly driven by efficiency gains from technologies such as more efficient appliances and electric two-wheelers and cars[28].

- **The cost of electrified technologies is falling rapidly and durably.** Technologies that manipulate electrons, including batteries, electric motors, power electronics, and heat pumps, follow steep learning curves: costs fall predictably as production scales. Since the early 1990s, battery pack costs have fallen nearly 99%, electric motor costs by a similar magnitude, and power electronics costs by 99.5%[29]. By contrast, structural fossil-fuel technology cost declines are not expected anymore, and operating costs are bounded by the underlying cost of fuel, as Indonesian manufacturers using oil boilers experienced directly during the 2026 Iran war price spike [Figure 8].

- **Electrification reduces exposure to fuel import bills and price volatility**, lowering risk for households and manufacturers alike (see Chapter 5). The 2026 Iran conflict made this concrete: oil prices rose above USD 100 per barrel, exposing Indonesian manufacturers using oil-based heat to a near-50% spike in fuel costs[30].

Electrification therefore offers a pathway to lower costs for households, increased competitive advantage for manufacturers, and improved energy resiliency if electricity demand can be satisfied by domestic sources. This will increase the probability for Indonesia to reach its ambitious economic growth targets. China illustrates the pace at which this shift can happen at scale: electricity's share of final energy demand has risen from around 15% in 2010, the same level Indonesia is at today, to over 30% now, driven by EVs, industrial electrification, and heat pumps[31,32]. Across transport and most of industry, electrified technologies are already, or will soon become, the lower-cost option. The question is how fast Indonesia captures this shift.

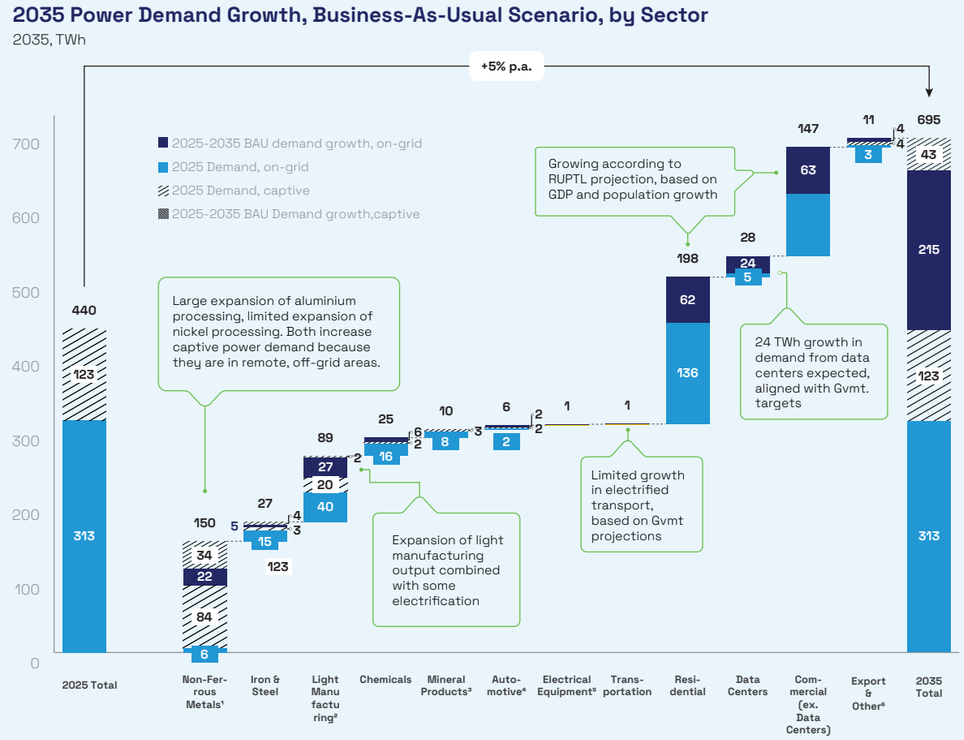
Using both scenarios helps illustrate not only the Business-as-Usual and High Electrification demand outlook, but also what the economic implications of a faster shift to electrified technologies would be for Indonesia.

26 US Department of Energy, www.fueleconomy.gov
27 IEA (2022) The Future of Heat Pumps
28 IEA (2022) An Energy Sector Roadmap to Net Zero Emissions in Indonesia
29 McCormick and D'Amico (2025) The Electric Slide
30 Around 5% of industrial final energy demand was oil in 2023. Source: MEMR 2024a.
31 Ember (2025) China Energy Transition Review
32 Enerdata (2025) World Energy & Climate Statistics – Yearbook 2025

1.3
Business-as-Usual electricity demand growth

In a Business-as-Usual (BAU) scenario, total electricity demand is set to grow by 5% per year between 2025-2035, from 440 TWh today to 695 TWh by 2035 [Error! Reference source not found.]. This trajectory reflects a continuation of historic economic growth of around 5% per year and the implementation of currently announced industrial projects, without a major acceleration in electrification or growth in electricity-intensive new sectors. Residential and commercial demand, non-ferrous metals, and data centres account for the largest increase in demand over the next decade.

Figure 6 | Non-ferrous metals, light manufacturing, residential, and commercial sectors are the largest contributors to BAU electricity demand growth.



Notes: For sectoral breakdown of demand assumptions, see accompanying technical appendix.1. Nickel, Aluminium, Copper, and other NF metals. 2. Food & Beverage, Textiles, Rubber, Pharma, Pulp & Paper 3. Cement, glass and ceramics 4. Manufacturing of cars and other transport vehicles. 5. Production of electrical products, including batteries and solar modules. 6. Includes other industries

Demand growth in the BAU scenario is driven primarily by four structural trends. The section below summarizes these trends[33]:

33 For more detailed assumptions on the sectoral demand modelling, please see the accompanying Technical Appendix.

- First, **rising residential and commercial electricity consumption** increases demand as incomes grow. Air-conditioning adoption is projected to continue its steady rise, with AC ownership increasing from around 12% of households in 2025 to roughly 24% by 2035. Together, **residential and commercial demand add +62 TWh and +63 TWh of demand between 2025-2035, respectively.**

- Second, **expansion of metals processing industries**, particularly aluminium and nickel smelting, adds substantial new electricity demand. The current pipeline of industrial projects is projected to add roughly 3 Mt of aluminium production capacity and around 350 kt of nickel processing capacity by 2035, making non-ferrous metals the single largest contributor to demand growth **(+60 TWh vs 2025).** However, most of this demand growth is expected to occur outside the main grid, with dedicated (captive) power plants. This is because metal processing facilities, particularly for nickel and aluminium, are often close to mines, in remote locations with no to limited grid access. As a result, roughly **15% of total electricity demand growth** in the BAU pathway is projected to be off-grid, captive demand.

- Third, **data centres emerge as a fast-growing source of electricity demand**. Indonesia's relatively low electricity prices make it an attractive location for digital infrastructure. Under the BAU **scenario, the expansion of the data centre pipeline of 2.7 GW adds around 24 TWh of additional electricity demand by 2035**. The government is actively supporting data centre roll-outs through tax exemptions and by allowing 100% foreign ownership in Special Economic Zones[34].

- Fourth, **continued expansion of light manufacturing and services** contributes additional demand growth (+**29 TWh vs 2025**, of which 27 TWh is on-grid). This includes growth in sectors such as food processing, textiles, and other manufacturing activities that expand alongside Indonesia's broader economic development.

1.4
High Electrification electricity demand growth

In a High Electrification scenario, electricity demand is projected to grow faster, reaching around 7% annual growth between 2025 and 2035. This results in 855 TWh of demand by 2035, around 20% higher than the 2035 demand in BAU [Figure 7]. This will increase Indonesia's per capita electricity consumption from ~1,300 to ~2,800 kWh/capita. Of total demand, around **655 TWh** is on-grid by 2035.

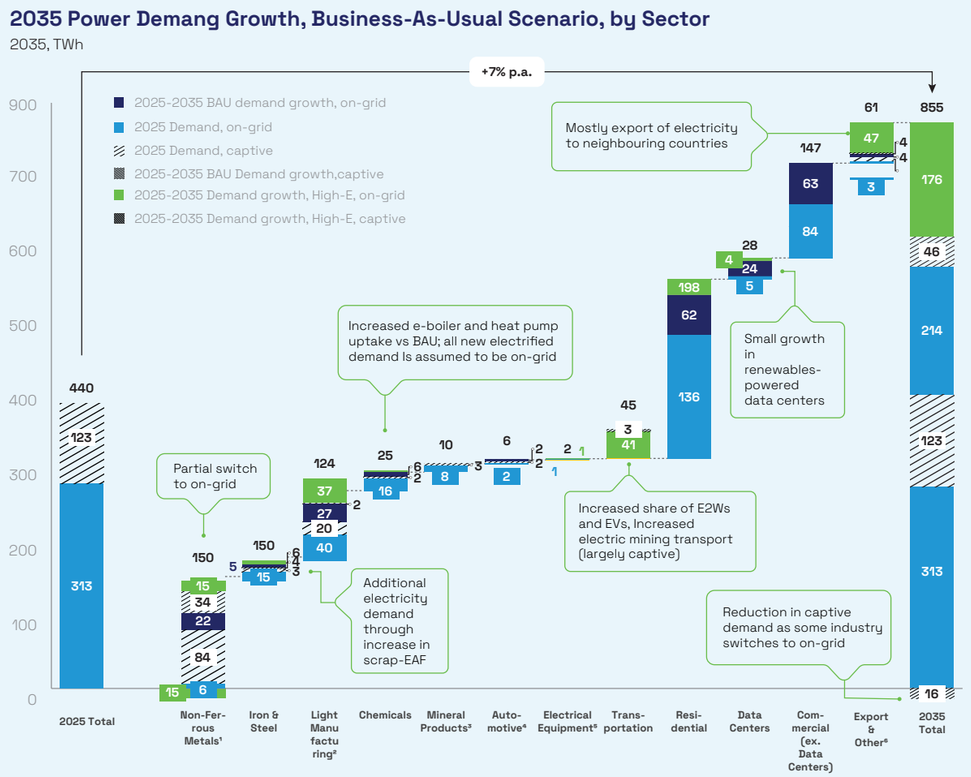
Concretely, demand growth in the High Electrification scenario is driven by two broader trends:

1. Increased electrification across the industry, transport, and residential sectors.

2. Additional demand is unlocked in growth sectors anchored on the availability of renewable power.

34 Research and Markets (2026) Indonesia Data Centre – Market Share Analysis, Industry Trends & Statistics, Growth Forecasts (2026–2031)

Figure 7 | Additional electricity demand growth is driven by light manufacturing, transport, export, and residential sectors in the High Electrification scenario.



Notes: For sectoral breakdown of demand assumptions, see accompanying technical appendix.1. Nickel, Aluminium, Copper, and other NF metals. 2. Food & Beverage, Textiles, Rubber, Pharma, Pulp & Paper 3. Cement, glass and ceramics 4. Manufacturing of cars and other transport vehicles. 5. Production of electrical products, including batteries and solar modules. 6. Includes other industries

First, **increased electrification across industry, transport and residential sectors** raises electricity consumption above the BAU pathway, through[35]:

- In **industry and manufacturing**, electric technologies gradually replace fossil-fuel heat in several processes, **increasing electricity demand by +43 TWh vs BAU** (+37 TWh in light manufacturing and + 6 TWh in Iron & Steel). This starts in the sectors where electrification is already cheaper or close to being cheaper than the fossil alternative [See Box B]. For example, in textile fibre production the share of electric boilers and heat pumps expands to around 42% of supply, while the share of coal-fired boilers declines from around 75% today to roughly 30% by 2035. In iron and steel production, the share of scrap-based electric arc furnace (EAF) production increases from roughly 30% to around 38%, replacing part of the blast furnace-basic oxygen furnace route [See Technical Appendix for full assumptions].

35 For more detailed assumptions on the sectoral demand modelling, please see the accompanying Technical Appendix.

- In **non-ferrous metals, 15 TWh** of electricity demand moves from captive to on-grid, as the grid gets expanded and more industry gets connected.

- In **transport, electric mobility expands significantly and electricity demand increases by +45 TWh versus the BAU scenario**. The total passenger vehicle fleet grows in both demand scenarios: car ownership rises from around 70 cars per 1,000 people to 110 cars per 1,000 people by 2035[36], while motorcycle ownership remains broadly stable at around 500 motorcycles per 1,000 people. The difference between scenarios is in the electrification share of this fleet: in High Electrification, electric cars reach around 26% of the total vehicle fleet and electric two-wheelers around 30% by 2035, compared with around 0.5% for cars and 0.6% for two-wheelers in the BAU scenario[37]. On top of that, heavy duty trucks used in the mining sector also electrify (37% of total fleet assumed to be electric by 2035), adding 4 TWh of demand, of which 1 TWh on-grid.

- **Residential electricity demand increases by +24 TWh vs BAU** by 2035, driven by increased cooling demand and electrification of cooking. **Higher cooling demand** increases electricity consumption **by +16 TWh vs BAU**, with air-conditioning ownership reaching around 38% of households by 2035, compared with roughly 24% in the BAU pathway, up from 12% today. **Electric cooking increases residential electricity demand by +8 TWh vs BAU** by 2035: while the share of households with a grid connection that can sustain electric cooking remains small (only ~3% of households in 2025 , ~4.5% in 2035), those households are assumed to almost fully electrify their cooking by 2035.

Second, potential **new electricity demand emerges from growth sectors that anchor renewable power supply**.

- Regional electricity trade expands as neighbouring countries seek low-carbon electricity imports, mostly to power data centres, leading to around **47 TWh of electricity exports to neighbouring markets by 2035**.

- Additional investment in **data centres**. While significant data centre demand already appears in the BAU scenario due to Indonesia's relatively low electricity prices, the availability of clean power attracts an additional segment of facilities from international hyperscale technology companies that actively seek low-carbon power supply and will push for renewable offtake arrangements when entering a market [See Box C]. As a result, electricity demand from data centres reaches **around 32 TWh by 2035**, compared with roughly **28 TWh in the BAU scenario.**[38]

Together, **faster electrification** and the emergence of **new growth sectors anchoring clean power** push electricity demand substantially above the BAU pathway.

36 This includes only private passenger cars.
37 Note that the adoption of E2Ws in the High Electrification scenario is a significant increase: in 2025, 0.2% of the two-wheeler fleet was electric.
38 The size and scale of future data center demand is uncertain and changing rapidly. This analysis assumes ~3 GW of data center build-out by 2035 in the High Electrification scenario, but one stakeholder mentioned the possibility of reaching ~20 GW by 2035.

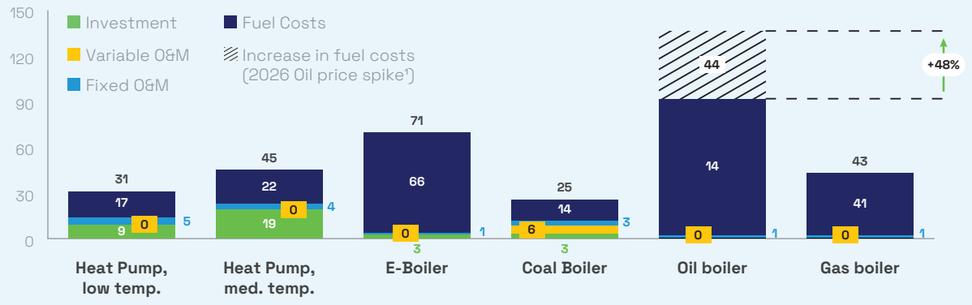
BOX B | First movers in industrial electrification

The first industrial applications to electrify are likely to be low-to-medium temperature heat processes, where commercially available technologies such as electric boilers and heat pumps can already replace fossil-fuel boilers [Figure 8]. These opportunities are strongest in light manufacturing sectors such as textiles, food processing, paper, and selected chemicals, where a large share of heat demand is below 200°C and electrification is already technically mature. Higher-temperature processes in cement, steel, and chemicals are expected to move later, as they remain harder to electrify and depend more on emerging technologies.

In Indonesia, these first movers are especially likely where firms currently use oil boilers, since oil-based heat is much more expensive than electric alternatives. Oil also leaves firms exposed to imported fuel price shocks, with costs able to rise sharply during geopolitical disruptions, as seen during the Iran war in early 2026. Figure 8 shows how the 2026 price spike caused an almost 50% increase in the cost of oil-based heat.

By contrast, coal boilers can still be cheaper than electrified options, weakening the purely economic case for electrification. However, in consumer-facing export sectors, pressure from international buyers can still make electrification strategically attractive even where coal remains low-cost, particularly as major brands move to phase out coal from their supply chains. This mechanism is explored in-depth in Chapter 5.

Figure 8 | Near-term electrification opportunities in industry.



Notes: 1. While most fuel costs remained stable between 2024-2026, oil prices spiked following the conflict in Iran in early 2026. This range represents the LCOH at a diesel price of 20,000 IDR/L (versus the previously assumed price of 13,400 IDR/L).
Source: Global Petrol Prices; PLN Statistics (2024); Direktorat Jenderal Mineral Dan Batubara (2026) Harga Acuan; Expert interviews; Levelized Cost of Heat adapted from Danish Energy Agency & MEMR (2024) Techno-Economic Analysis of Decarbonization Technology options for energy end-use sectors in Indonesia.

BOX C | Amazon Web Services pushes for renewables

Data centre demand is already pulling Indonesia's renewable procurement framework forward. Amazon Web Services (AWS) launched its Asia Pacific (Jakarta) Region in December 2021, committing USD 5 billion of investment over 15 years across data centre construction, operations, and local supply chain spend, with an estimated contribution of USD 10.9 billion to GDP and 24,700 direct and indirect jobs sustained annually over the period39. The AWS commitment is part of a broader hyperscaler build-out in Indonesia that includes Microsoft, Google, Oracle, and Alibaba, and that is projected to lift the country's hyperscale data centre market from USD 3.5 billion in 2025 to USD 8 billion by 2031[40].

To match data centre load with clean supply, AWS signed a power purchase agreement with PLN in November 2022, contracting 210 MW of capacity across four utility-scale Solar PV projects in Java and Bali. The deal was Indonesia's first corporate PPA for offsite facilities, opening a procurement route that had previously been blocked by PLN's monopoly on retail electricity sales and the historic difficulty of private suppliers using the PLN grid.

Construction across all four sites has started, and PLTS Bali Timur started commercial operations in September 2025. The remaining three sites in Karangkates, Saguling and Bali Barat are currently still under construction with commercial operation targeted for 2026[41, 42, 43, 44, 45].

PLN has signalled intent to extend the model to other corporate offtakers, and the regulatory environment has continued to evolve, with MEMR Regulation 5/2025 codifying clearer principles for renewable PPAs.

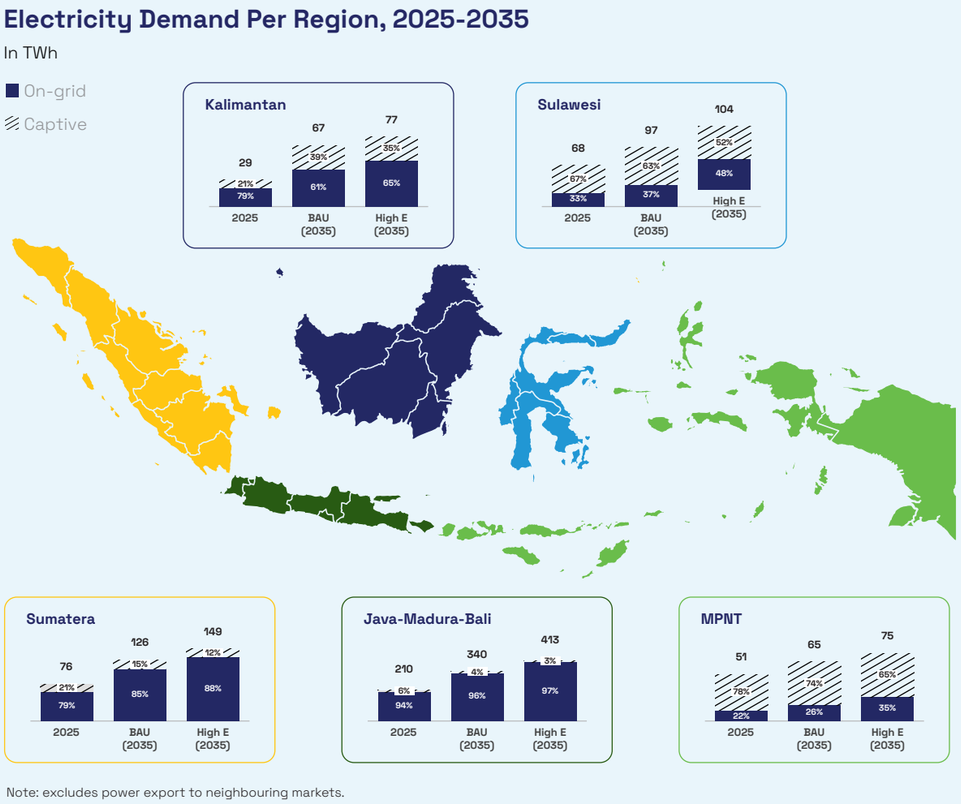
The AWS case shows that corporate demand for clean power can be a lever for both renewable deployment and regulatory reform. Capturing the next wave of data centre and AI investment will depend on whether this procurement pathway can be scaled, with multi-hundred-megawatt corporate green PPAs becoming standard rather than exceptional, alongside the transmission, permitting, and storage build-out required to deliver competitively priced renewable generation at the volumes data centre load now demands.

39 Amazon Web Services (2021), AWS Launches AWS Asia Pacific (Jakarta) Region in Indonesia
40 Mordor Intelligence (2025), Indonesia Hyperscale Data Center Market Size, Share & 2030 Growth Trends Report
41 Medco Energi (2025) Medcosolar Bali Timur
42 PLN Nusantara Power (2026) Accelerating the Clean Energy Transition, PLN Nusantara Power Strengthens the Development of the Karangkates Floating Solar Power Plant
43 PT Indo ACWA Tenaga Saguling (2025) Saguling Floating Solar PV Commencement Ceremony
44 Medco Energi (2025) Annual Report
45 No sources confirm the commercial operation date for the sites still under construction.

1.5
Demand growth will differ by region

Electricity demand growth will not be evenly distributed across Indonesia. Differences in population density, industrial activity, and the location of resource deposits mean that some regions will see substantially faster growth than others, and that the share of demand met by on-grid versus captive power varies materially across the archipelago [Figure 9].

Figure 9 | Electricity demand growth varies by region, especially on-grid versus captive demand.



Note: excludes power export to neighbouring markets.

Overall, electricity demand grows across all regions, but Jamali (Java-Madura-Bali) and Sumatera, the most densely populated regions, dominate, together accounting for around 70% of Indonesia's total electricity demand throughout High Electrification scenario by 2035. In all scenarios, Jamali accounts for approximately 50% of Indonesia's total electricity demand between 2025 and 2035. Sumatera, the second-largest demand region, grows from around 75 TWh today to around 125 TWh in BAU and 150 TWh in High Electrification by 2035, continuing to make up almost 20% of Indonesia's demand. The other regions, Sulawesi, Maluku-Papua-Nusa Tenggara (MPNT) and Kalimantan, see fast growth from a smaller base, driven by metals processing rather than population.

- **Residential and transport demand broadly scale with population**. Growth in these sectors is therefore concentrated in major demand centres, particularly Jamali and Sumatera, driven primarily by population and commercial expansion.

- **Industrial demand is structurally more uneven.** Captive power dominates electricity supply in the resource-driven outer islands: by 2035, captive demand accounts for around 52-63% of total demand in Sulawesi and 66-74% in MPNT, compared with only 3-4% in Java-Madura-Bali. Key growth sectors such as mining, smelting, and metals processing are located close to resource deposits rather than demand centres, and the largest projects are concentrated in remote regions with limited grid connectivity.

    - Nickel processing demand is split across Sulawesi and Maluku, Papua, and Nusa Tenggara (MPNT) and is almost entirely captive: in both scenarios, nickel processing alone accounts for around 100 TWh of captive demand across these two regions by 2035, of which roughly 55 TWh is in Sulawesi and 45 TWh in MPNT.

    - Aluminium processing is concentrated in Sumatera (15 TWh) and Kalimantan (30 TWh), and half of the demand is satisfied by captive power plants.

These regional patterns also shape how Indonesia's overall captive-versus-on-grid demand mix will evolve. **Captive power accounts for around 30% of total electricity demand today, and this share will decline over the next decade, even more sharply under High Electrification.** By 2035, captive demand falls to around 25% in BAU and around 20% in the High Electrification scenario. The sharper decline in High Electrification reflects the nature of the additional demand: electrification of transport, light industry, and residential cooling is inherently on-grid activity, while the captive-heavy industrial demand in outer islands grows from a smaller base. Additionally, our modelling assumes a limited (~10%) shift of captive demand to on-grid demand by 2035 in the High Electrification scenario.

> **Captive power accounts for around 30% of total electricity demand today, and this share will decline over the next decade, even more sharply under High Electrification.**

Realising this shift will require accelerated grid expansion, particularly to connect industrial clusters in the outer islands that currently rely on dedicated captive supply. Indonesia's archipelagic geography makes this challenging: fragmented grids and limited interconnection between islands constrain the efficient balancing of supply and demand, particularly between resource-rich outer islands with surplus generation potential and high-demand centres such as Java. Without targeted grid expansion and interconnection, a growing share of new demand will continue to be met outside the main grid, limiting the system's ability to integrate lower-cost renewable generation.

1.6
Meeting rising electricity demand will require a rapid expansion of Indonesia's power system

Both the BAU and High Electrification scenarios imply a substantial expansion of Indonesia's electricity system over the next decade. Electricity demand is projected to grow from **440 TWh today to around 695–855 TWh across scenarios by 2035**, equivalent to **around 5–7% annual growth** depending on the demand pathway. **On-grid demand grows to 525 (BAU)-655 (High-E)** TWh

The next decade of electricity demand growth is only the start. The Energy Transitions Commission projects global electricity demand will roughly triple by 2050 as transport, heating, industry, and e- fuel[46] production shifts onto the grid, and Indonesia will likely follow the same trajectory[47]. Building the supply needed to meet 2035 demand therefore lays the foundation for a much larger system beyond.

If electricity supply does not expand in line with this demand, economic growth will be constrained. Across global supply chains, energy-intensive sectors such as metals processing, manufacturing, and data centres increasingly require electricity that is not only reliable and competitively priced, but also clean (see Chapter 5). Delays in power system expansion and renewable deployment could therefore slow investment, weaken Indonesia's industrial competitiveness, and limit its ability to capture emerging growth opportunities. Moving to a cleaner power system would also allow Indonesia to position itself for economic opportunities across cleantech supply chains, including in battery and EV supply chains.

The scale and timing of new electricity supply will therefore play a decisive role in determining whether Indonesia's growth ambitions can be achieved. Ensuring that new electricity supply can be deployed quickly, reliably, and at competitive cost will be essential to support industrial expansion, attract investment, and meet rising household demand.

The chapters that follow assess what it would take to expand Indonesia's power system at the scale required under different demand and supply pathways. They examine Indonesia's current power system and expansion plans, the availability of renewable resources, and explore whether a higher share of renewables could deliver additional economic benefits while meeting rising electricity demand.

46 Such as hydrogen or E-SAF
47 ETC (2025), Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems





Chapter 2

Indonesia's power supply: large renewables potential, limited deployment

Chapter 1 demonstrated that Indonesia will undergo rapid electricity demand growth over the coming decade. Meeting that demand will require a major expansion of the power system. Indonesia has the renewable resource base to support this expansion many times over, with solar standing out for its scale, build speed, and globally falling costs. Yet renewables deployment has consistently lagged peers, and the current RUPTL plan does not close the gap. The barrier is not resources but the conditions for commercial deployment: project economics remain weak, suppressed by high costs and low revenues, and market replication has stalled despite the success of first-mover projects. The recently announced 100 GW solar programme marks a step change in ambition, its delivery depending on parallel action to bring costs down and scale demand to absorb new generation.

This chapter sets out current the supply-side picture in five steps. Section 2.1 outlines the 2025-2034 RUPTL and its delivery track record. Section 2.2 describes Indonesia's renewable resource base and current deployment. Section 2.3 looks at the electricity generation costs for various sources today, and section 2.4 examines why first-mover projects have not triggered broad replication. Section 2.5 closes with the 100 GW solar programme.

2.1
The 2025-2034 RUPTL plans for significant renewables expansion, but delivery has repeatedly fallen short

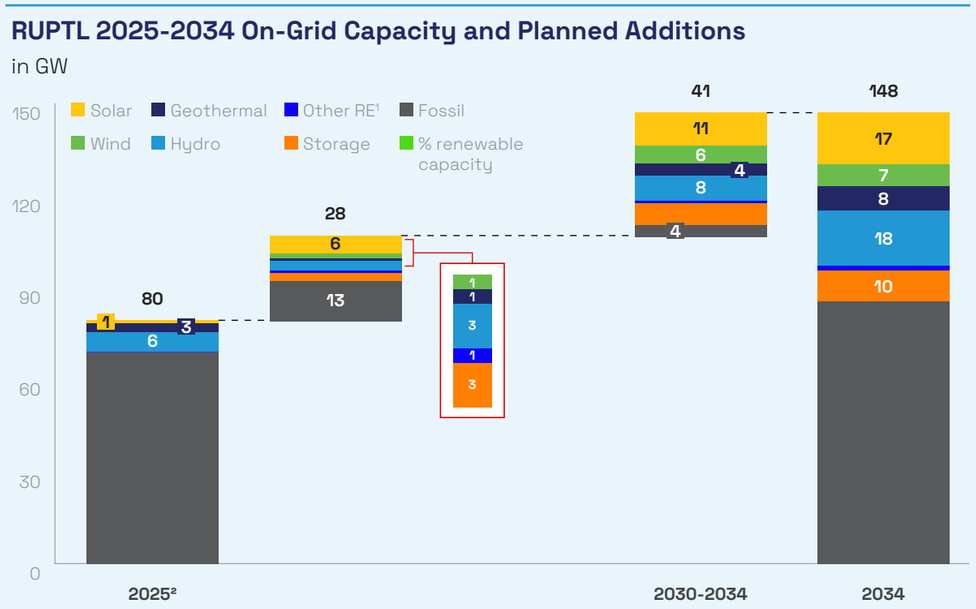
Indonesia's power sector expansion is guided by the *Rencana Usaha Penyediaan Tenaga Listrik* (RUPTL), the national electricity supply plan prepared by the state utility PLN and approved by the Ministry of Energy and Mineral Resources. The RUPTL provides the government's official roadmap for power system expansion, setting out planned additions of generation capacity, transmission infrastructure, and supporting investments. It is updated periodically (previous versions were published in 2019 and 2021) and typically uses a ten-year planning horizon for power system development. The current RUPTL was finalised before the government's August 2025 announcement of a 100 GW solar PV programme by 2030 (see Section 2.5) and is expected to be revised in the coming months to reflect that ambition. The figure below should therefore be read as the current plan, which is likely to evolve.

Indonesia's power sector expansion is guided by the *Rencana Usaha Penyediaan Tenaga Listrik* (RUPTL),

The current RUPTL covers the period 2025–2034 and outlines a major expansion of Indonesia's electricity system over the coming decade [Figure 10]. In total, the plan schedules the addition of approximately 60 GW of new on-grid generation capacity – a ~60% increase versus Indonesia's current grid-connected installed capacity of 96 GW. Around 42 GW of this new capacity is planned to come from renewable energy, including 17 GW of solar PV, 12 GW of hydropower, and 7 GW of wind, alongside smaller additions of geothermal and other renewable technologies (e.g., bioenergy). The remaining ~17 GW is expected to come from fossil generation, primarily coal and gas and ~10 GW of storage, consisting of 6 GW of BESS and 4.2 GW of Pumped Hydro Storage.

In the plan, fossil additions are front-loaded: most gas and coal additions are scheduled for 2025-2029, while the largest renewables expansion happens after 2030. Storage is developed on a similar back-loaded timeline: only ~3.5 GW out of the 10 GW of storage is targeted for delivery by 2030. Renewable capacity only reaches around 30% of capacity by 2035, with the remainder dominated by coal- and gas-fired power plants. Delivering the 100 GW solar programme on top of this baseline would represent a major acceleration in renewables build-out, and is examined in Section 2.5.

Figure 10 | Current on-grid generation capacity and planned additions under RUPTL 2025-2034.



Notes:. 1. Includes bio-energy and nuclear. 2. Includes only on-grid PLN supply
Source: MEMR (2025), Handbook of Energy & Economic Statistics of Indonesia 2025

The current RUPTL covers the period 2025–2034 and outlines a major expansion of Indonesia's electricity system over the coming decade [Figure 10]. In total, the plan schedules the addition of approximately 60 GW of new on-grid generation capacity – a ~80% increase versus Indonesia's current grid-connected installed capacity of 80 GW[48]. Around 42 GW of this new on-grid capacity is planned to come from renewable energy, including 17 GW of solar PV, 12 GW of hydropower, and 7 GW of wind, alongside smaller additions of geothermal and other renewable technologies (e.g., bioenergy). The remaining ~17 GW is expected to come from fossil generation, primarily coal and gas and ~10 GW of storage, consisting of 6 GW of BESS and 4.2 GW of Pumped Hydro Storage (PHS).

48 Note: only includes on-grid PLN supply. Source: ESDM (2026) Handbook Of Energy & Economic Statistics Of Indonesia 2025

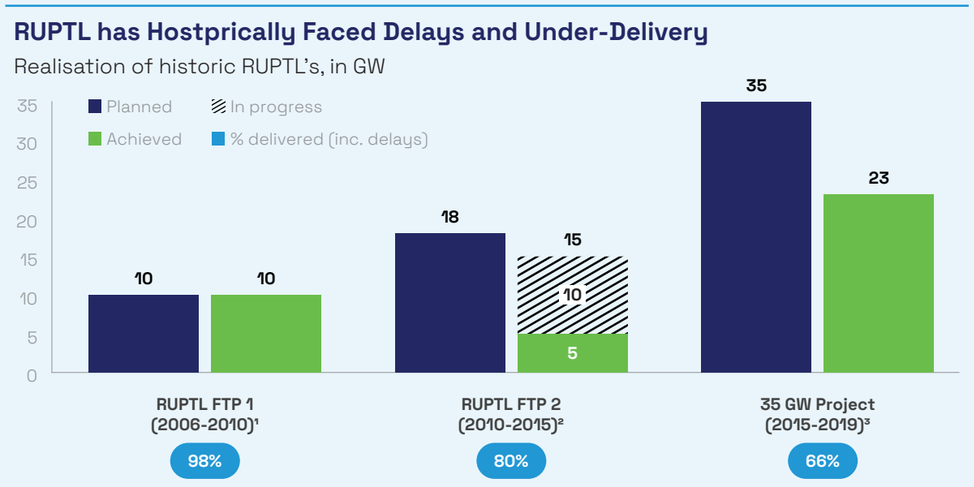
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In theory, the capacity additions outlined in the RUPTL are sufficient to accommodate electricity demand growth under both the BAU and High Electrification scenarios to 2035. In practice, delivery is uncertain. The previous 35 GW programme (2015-2019) delivered only around 66% of planned capacity, and that figure includes projects completed with significant delays. Earlier programmes, including Fast Track Programmes I and II, have faced similar issues, although they reached higher completion rates. Permitting bottlenecks, financing constraints, and project development challenges have repeatedly slowed build-out below planned rates [Figure 11].

Delivery risk within the RUPTL is concentrated in the renewable build-out. Not because renewables are intrinsically harder to deliver, but because **the plan sequences fossil capacity first**: most coal and gas additions are scheduled for 2025-2029, while the bulk of renewable capacity is back-loaded to 2029-2034. Projects planned for a later timeline face the highest risk of delay, deprioritisation, or cancellation if financing, permitting, or system planning challenges emerge.

Figure 11 | Indonesia has historically delivered below RUPTL targets.



- All three programs have faced **significant delays** in completing its target. FTP 1 target was met 4 years behind schedule and as of 2023, FTP 2 is still completing its target.
- The 35 GW program has **prioritized coal-fired power plants**, creating delays in renewable energy development.
- Note on the most recent plans: The 2019-2028 plan was in force for only two years before being replaced by the 2021-2030 plan, making its delivery difficult to assess. The 2021-2030 plan is still ongoing, but underdelivery appears likely: by early 2025, only 1.6 GW had been commissioned, versus ~10 GW planned[5].

Notes: 1) IEEFA (2024); 2) No official data on FTP 2 achievement, data was gathered from IEEFA estimations; 3) Inside Indonesia (2020) 4) CREA and RUPTL 5) IESR (2025) Government needs to ensure strategy to achieve renewable energy target in RUPTL

2.2
Indonesia has strong renewable resources, but deployment is lagging

Indonesia has the resource potential to scale renewables far beyond RUPTL. Technical potential is estimated at over 7,700 GW of solar PV[49], 155 GW of wind[50], 95 GW of hydropower[51], 24 to 2,160 GW of geothermal[52], around 30 GW of biomass power[53], and approximately 7,300 GWh of pumped hydro storage[54]. These resources serve distinct roles: geothermal and biomass operate continuously and can directly replace coal as firm baseload; solar and wind are variable but increasingly paired with storage to firm up supply.

Geothermal and hydropower deserve particular attention as a round-the-clock, low-carbon baseload resources. The sections below provide in-depth information on their resource, status in Indonesia, and how to scale them further.

Geothermal and hydropower deserve particular attention as a round-the-clock, low-carbon baseload resources.

Geothermal in Indonesia: the baseload renewable that remains largely untapped

Indonesia holds an estimated 24 (government estimate) - 2,160 GW (IESR research estimate, including next-generation potential) of geothermal potential, the largest untapped geothermal resource base in the world[55]. Fully realizing this potential would allow geothermal energy to meet Indonesia's process-heat demand in key manufacturing sectors and strengthen firming capacity in a renewable grid, significantly reduce the nation's reliance on coal and imported fuels. Yet only 2.7 GW of geothermal capacity is operational today, equal to only around 10% of technical potential[56].

The strategic case for accelerating development is strong. Unlike solar or wind, geothermal delivers firm, dispatchable power: capacity factors exceed 90%, making it capable of replacing coal as a baseload source without storage or backup. One megawatt of geothermal capacity delivers roughly twice the annual generation of one megawatt of solar capacity. The RUPTL 2025-2034 reflects this value, targeting an additional 5.2 GW of geothermal capacity over the next decade. Delivery, however, has lagged historically: in 2025, Indonesia added only 113 MW against the 500 to 600 MW per year implied by the RUPTL pathway.

Three structural barriers explain the delivery gap:

- **Exploration risk.** Upfront resource exploration costs USD 30 to 50 million with no recourse if the resource proves insufficient, and full development of a 100 MW site can reach USD 400 million. This reduces project IRRs to 8-9%, well below the 10-12% developers require, producing a financing gap before a single kilowatt-hour is generated.

- **Land access.** Most geothermal potential sits in or adjacent to forest areas, where Forestry Borrow-to-Use Permits involve costly offsetting requirements and engagement across multiple government agencies, adding years to permitting timelines.

- **Social licence.** In several cases, including Flores and Mount Lawu, community opposition over water sources, land disruption, and sacred sites has stalled projects entirely, driven in part by limited public consultation at project outset.

Accelerating geothermal development requires three targeted interventions. First, **upstream risk mitigation** through a permanent, capitalised facility providing contingent financing for exploration drilling, with proven sites then auctioned to private developers, building on the World Bank-backed Geothermal Resource Risk Mitigation (GREM) facility model. Second, scaling **permitting reform**; pilot cases have already reduced licensing from up to 18 months to as little as seven days, and this process should be replicated widely. Third, **standardised benefit-sharing frameworks and mandatory early consultation** should be embedded in the licensing process. This should be paired with **public education and socialisation on geothermal's benefits and environmental-impact mitigation**, so communities are better informed and more likely to support development, reducing the project-by-project social negotiation that has repeatedly extended development timelines by years.[57][58]

Hydropower in Indonesia: the Swiss-army knife of the power generation mix

Indonesia has approximately 95 GW of technical hydropower potential, concentrated primarily in Papua, Kalimantan, Sumatra, and Sulawesi. As of December 2025, total installed capacity was around 6.3 GW, consisting of 5.1 GW of large hydropower (PLTA) and 1.2 GW of mini and micro hydropower (PLTM/PLTMH) across Indonesia, reaching less than 7% of total potential. The RUPTL 2025–2034 targets 16 GW of new hydropower capacity, the second-largest planned renewable addition after solar.

Indonesia has approximately 95 GW of technical hydropower potential, concentrated primarily in Papua, Kalimantan, Sumatra, and Sulawesi.

Hydropower is uniquely versatile: it provides dispatchable firm power without battery storage, can serve as baseload or distributed supply, supports electricity storage through pumped hydro, and can host floating solar PV on existing reservoirs. PLTS Cirata demonstrates the latter: a 192 MW floating solar installation added atop an existing reservoir has created one of Southeast Asia's largest hybrid renewable systems without additional land use.

Large-scale hydropower offers transformational capacity but carries commensurate environmental and social risks. Flagship projects in the pipeline, including the 9 GW Kayan

49 IESR (2025) Unlocking Indonesia's Renewables Future
50 Energy Transition Partnership (2024) Roadmap Onshore Wind Energy Development in Indonesia
51 ESDM (2023) Percepat Upaya Transisi Energi, Menteri ESDM Dorong Pemanfaatan Tenaga Hidro
52 IESR and project InnerSpace(2025) The Future of Geothermal in Indonesia. Note: this potential includes next-generation potential from hot dry rock.
53 IESR (2025) Unlocking Indonesia's Renewables Future
54 IESR (2025) Unlocking Indonesia's Renewables Future
55 Antara News (2025) Illuminating the future with geothermal power
56 Think Geoenergy (2025) Indonesian Government sets direction for geothermal growth at IIGCE 2025
57
58

Cascade in North Kalimantan and the 1.3 GW Mentarang plant, involve reservoir inundation of high-conservation-value forests, displacement of Indigenous communities, and permanent alteration of river ecosystems.

Mini and small hydropower (below 10 MW) has a structurally different profile: run-of-river configurations avoid large inundation, environmental footprints are modest, and projects are well suited to remote eastern Indonesia, where grid extension is uneconomic and diesel dependence is high. Mini hydro is Indonesia's fourth-largest source of renewable capacity, with approximately 486 MW installed, yet represents only a fraction of the available potential.

Targeted interventions are needed to unlock further hydropower growth. For large-scale projects, the priority is to front-load environmental and social assessment before site selection, using spatial planning to identify and avoid sensitive areas as a precondition for tendering, rather than a source of later dispute. Without this, international capital will not return. Floating solar should be mainstreamed as a standard co-development option within PLN's tendering process for existing and planned reservoirs, given its low marginal cost and near-zero land footprint.

For mini hydro, the bottlenecks are economic and regulatory. Local developers face limited access to finance and high borrowing costs, which significantly increases project costs, while PLN ceiling tariffs are widely regarded as too low, as price-only competitive processes drive tariffs to unfeasible levels. This leaves many technically viable projects uncontracted. In addition, the equity and partner requirements attached to PLN and Sub-Holding development schemes can complicate participation for smaller developers[59]. A revised feed-in tariff reflecting actual remote-area development costs, simplified permitting for run-of-river schemes, and standardised PPAs would unlock a pipeline that is technically ready but commercially stranded.

Wind plays a more limited role in Indonesia's power system

Indonesia's technical wind potential of 155 GW does not yet incorporate what is economically viable. Sitting close to the equator, Indonesia has low average wind speeds: around 4 m/s at 100m height[60], less than half the level of high-resource markets such as Denmark or the UK. Resources are concentrated in pockets, primarily East and West Nusa Tenggara, southern Sulawesi, southern Java, and parts of Aceh and Papua. Only 154 MW is currently installed, from two farms in South Sulawesi (Sidrap and Tolo) [61]. Wind can play a useful role in specific high-resource locations but is unlikely to scale to the level of solar.

59 The RUPTL sets out three development schemes: PLN, PLN Sub-Holding, and IPP. Under the PLN scheme, engineering, procurement and construction can be carried out by PLN directly or assigned to a Sub-Holding, with two execution options: 100% Sub-Holding (P.100) or 51% Sub-Holding with a 49% partner (P.51). Under the IPP scheme with a mandatory-partner option, PLN Sub-Holding participation is capped at 30%. For mini-hydro developed under the IPP scheme, there is no PLN Sub-Holding participation (100% IPP).

60 Plain et al. (2022) How offshore wind could become economically attractive in low-resource regions like Indonesia, iScience

61 Energy Transition Partnership (2024) Roadmap for Onshore Wind Energy Development in Indonesia

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Figure 12 | Solar PV projects can be constructed the fastest out of the renewable and fossil generation options.



Source: NS Energy Business; CNN Indonesia; expert interviews, Global Energy Monitor Wiki; Gumber et al (2024) A global analysis of renewable energy project commissioning timelines; Newposkommando; Boltim; Power Technology; Nippon Koei (2025).

Within this resource base, solar stands out for three reasons: resource scale, build speed, and cost trajectory:

- **Solar has by far the largest technical potential of any technology in Indonesia's renewable mix**, at over 7,700 GW, with around 166 GW already estimated to be at commercially viable sites[62]**.** Its modularity allows deployment across diverse geographies and use cases, from large utility-scale plants to rooftop and distributed systems. Previous IESR analysis suggests that **solar could in principle supply 88% of Indonesia's electricity demand by 2060, an exceptionally high share that underlines the scale of the opportunity[63].**

- **Solar can be built fast**. Utility-scale solar PV projects can be constructed within six months to two years, particularly when land access and grid connection are secured in advance. New coal plants, by contrast, typically take four to six years from the start of construction to commercial operation. In a system facing 5-7% annual demand growth, that difference matters: solar can respond to rising demand within planning cycles where new coal, geothermal or hydropower simply cannot [Figure 12]

Globally, solar costs have fallen dramatically over the past decade and continue to fall.

- **Globally, solar costs have fallen dramatically over the past decade and continue to fall**. Solar electricity generation is intermittent, so scaling it also requires storage and system-flexibility solutions; battery (BESS) investment costs are also declining rapidly, increasingly enabling round-the-clock generation using solar plus batteries. Section will look 3.1 at global trends in solar and batteries, and the direction of travel is clear: solar is becoming the lowest-cost source of new generation across most sunny climates, and Indonesia's high solar irradiation gives it a natural advantage in capturing that trend.

Solar's advantages comes with one qualification: solar only generates when the sun shines, so realising its full potential depends on the ability to shift that generation to other hours through storage. How costly that is depends heavily on geography. Low-latitude, sun-belt countries such as Indonesia face a lighter balancing challenge than high-latitude, wind-belt countries: solar output is consistent across the year, so the storage task is mostly daily (shifting midday generation into the evening peak) rather than the more complicated and expensive seasonal storage (storing summer generation for winter demand, as wind-dependent systems often must). Daily balancing, met mainly through batteries and demand-side flexibility, is comparatively low-cost and falling further as battery costs decline (see Chapter 3). As a result, sun-belt systems built around solar and batteries can reach total system costs at or below today's fossil-fuel levels, an advantage wind-dominated systems in higher latitudes do not share to the same degree64. Building out storage will also support continued reliability of Indonesia's power grid at higher shares of variable solar generation.

62 IESR (2025) Unlocking Indonesia's Renewables Future
63 IESR (2021) Deep decarbonization of Indonesia's energy system
64 ETC (2025) Power Systems Transformation

Box C | Rooftop Solar

Rooftop solar can scale fast, but Indonesia's quota system is holding it back. Pakistan shows how quickly distributed solar can move when economics are compelling. Between 2023-2025, Pakistan deployed 27 GW of distributed solar, the same cumulative capacity as all the operating coal, gas and oil plants ever built in Pakistan[65]. This boom was caused by the low costs and higher availability of solar + storage compared to electricity supplied by the grid.

Indonesia remains far behind, with a total installed rooftop solar capacity of 775 MW in 2025[66]. Growth is held back not by rooftop space, but by regulation: under MEMR Regulation No. 2/2024, grid-connected rooftop solar projects require prior approval through an application process and are subject to system-level quotas[67].

How the quota framework works. The total quota allowance for 2024-2028 is 5.7 GW[68], divided across PLN's 11 power systems, and limited per year: 901 MW in 2024, 1,004 MW in 2025, 1,065 MW in 2026, 1,183 MW in 2027, and 1,593 MW in 2028[69]. Over 70% of the 2024 quota was allocated to the Java-Madura-Bali system, with the remainder distributed across Sumatra, Sulawesi, Kalimantan, and the eastern islands. Within each system, individual capacity is allocated first-come-first-served through bi-annual application windows in January and July. PLN justifies the gradual ramp-up on grid stability grounds: rooftop solar's intermittent output is said to require careful integration into the grid.

Three issues with the current framework recur in industry and analyst commentary. First, the annual quotas are very low relative to Indonesia's broader solar ambitions, with the 5.7 GW cumulative quota over 2024-2028 representing only a small fraction of the 100 GW solar programme, and demand exceeds availability. In the January 2026 auction, 304 MW of the 485 MW available was allocated to systems already on the waiting list from the previous round, before any new applicants could be considered[70]. Second, net metering was abolished under MEMR Regulation 2/2024. Customers can no longer offset exports to the grid against their electricity bills, materially weakening the economics of rooftop solar[71]. Third, application windows are limited to twice a year, and in high-demand systems, applicants may not secure a quota allocation, delaying projects by another six months.

65 Ember (2026) The solarization of Pakistans energy economy
66 PLN presentation, Dec 2025
67 Ashurst (2024), Indonesia's New Rooftop Solar PV Regulation: a Difficult Balancing Act
68 As of July 2026
69 IESR (2024), Efforts to Encourage the Effectiveness of Rooftop Solar Quota Fulfillment
70 Katadata (2026) War Kuota PLTS Atap di Tengah Mimpi Kemandirian Energi
71 ABNR (2024), Indonesia Issues New Rules on Operation of Rooftop Solar, Abolishes Net Metering

BOX D | Floating Solar: a promising opportunity to scale solar on Indonesia's reservoirs

Floating solar is particularly well-suited to Indonesia. Java hosts around 56% of the country's population on just 7% of its land area, reaching a population density of around 1,200 people per km², around 2.5 times denser than India, 4 times denser than Vietnam, and 8 times denser than China[72][73]. Solar deployment on Java therefore faces intense competition for land. Floating solar sidesteps this constraint by using existing reservoir surfaces. Most of Indonesia's near-term floating solar pipeline sits on existing hydropower reservoirs, allowing co-location with hydropower generation and grid infrastructure that is already in place. Government officials estimate that Indonesia could host at least 28 GW of floating solar across its reservoirs and lakes[74].

Cirata is the first proof point of large-scale floating solar in Indonesia. The 192 MWp Cirata Floating Solar Plant in West Java was inaugurated in November 2023, a joint venture between Masdar and PLN Nusantara Power. It is currently Southeast Asia's largest floating solar facility[75]. The site also illustrates the structural complementarity between floating solar and hydropower: hydropower peaks during the rainy season while solar generation peaks during the dry season, stabilising output across the year.

The pipeline beyond Cirata. Several floating solar projects on reservoirs are in active development. The 92 MWp Saguling project (West Java, PLN Indonesia Power and ACWA Power) began construction in October 2025[76], with commercial operations targeted for November 2026[77]. Three further 100 MW projects are advancing under PLN planning: Gajahmungkur, Kedung Ombo, and Jatigede[78][79]. A 48 MW project at natural lake Singkarak (West Sumatra) is being developed by PLN and ACWA[80]. Beyond these, the RUPTL 2025-2034 names additional pipeline sites including Sutami (East Java) and Jatiluhur (West Java)[81].

Two barriers are slowing the scale-up of floating solar. First, competing reservoir uses and the community concerns they can cause. Many of Indonesia's reservoirs support floating net cage aquaculture, a primary livelihood for surrounding communities, and floating solar installations may require relocating these cages. Cirata's design accommodated continued aquaculture across the rest of the reservoir surface, but replication of that model at scale is not yet standardised[82]. At lake Singkarak, the only large project in the pipeline that sits on a natural lake, local fishers have raised concerns about impacts on the fish population, compounded by trust issues following an earlier hydropower-related flash flood83. Floating solar's social licence depends on credible early consultation and equitable benefit-sharing. Second, **the price for using the water surface is highly variable, adding uncertainty**. The water surface price varies from site to site, adding a layer of cost uncertainty comparable to land acquisition for ground-mounted solar and leaving developers and financiers without a predictable basis for project economics.

72 BPS-Statistics Indonesia (2024), Population Statistics 2024
73 World Bank (2024), Population Density Indicator
74 Indonesian government estimate, as reported by Reuters (2021), Indonesia begins work on Southeast Asia's largest floating solar plant.
75 ANTARA News (2024), Cirata floating solar power plant: Indonesia's green energy milestone.
76 Reuters / SolarBytes (2025), Indonesia begins 92 MW floating solar project in West Java
77 Renewables Now (2025), ACWA, PLN secure USD 60m for floating solar project in Indonesia
78 Asian Infrastructure Investment Bank (2025), Indonesia: Proyek Hijaunesia Staple Financing – Gajahmungkur 100 MW Floating Solar PV Project.
79 ANTARA News (2025), Floating solar power plants to energize Central Java.
80 Mongabay Indonesia (2025), Tragedy haunts community on shore of Sumatra's largest solar farm.
81 IESR (2025), The Big Role of Floating Solar Power Plants in Realizing RUPTL 2025-2034
82 ESA Global Development Assistance (2025), Understanding the planning challenges for floating solar PV in Indonesia

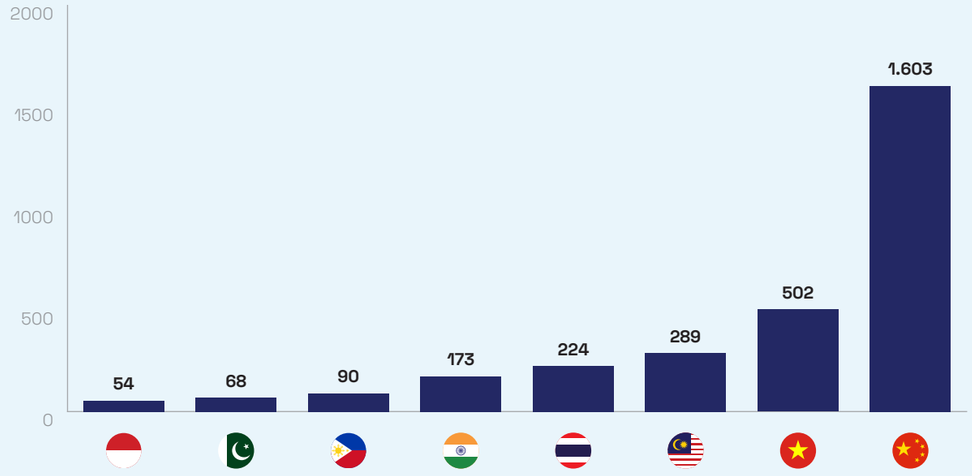
83 Mongabay Indonesia (2025), Tragedy haunts community on shore of Sumatra's largest solar farm.

While renewable resource is abundant, large-scale deployment of renewables has not yet taken off in Indonesia. At the end of 2025, Indonesia had only installed ~10 GW of on-grid renewables (0.5 GW solar, 0.1 GW wind, 6 GW hydro, 2.8 GW geothermal)[84]. Compared to regional peers, per-capita installed capacity is low at only 54 MW per million people, versus 90 MW per million people in the Philippines, 173 MW per million people in India or 502 MW per million people in Vietnam [Figure 13]. Despite having one of the largest renewable resource bases in Southeast Asia, Indonesia has barely begun to tap it. The constraint is not resources but the conditions for commercial deployment, and those conditions have so far only aligned for a few strategic projects, profiled in Section 2.3.

Figure 13 | Renewable capacity is lagging in Indonesia compared to regional peers.

Indonesia is Lagging Behind Regional Peers in The Deployment Of Renewable Capacity

Renewable capacity per capita, MW per million people, 2025

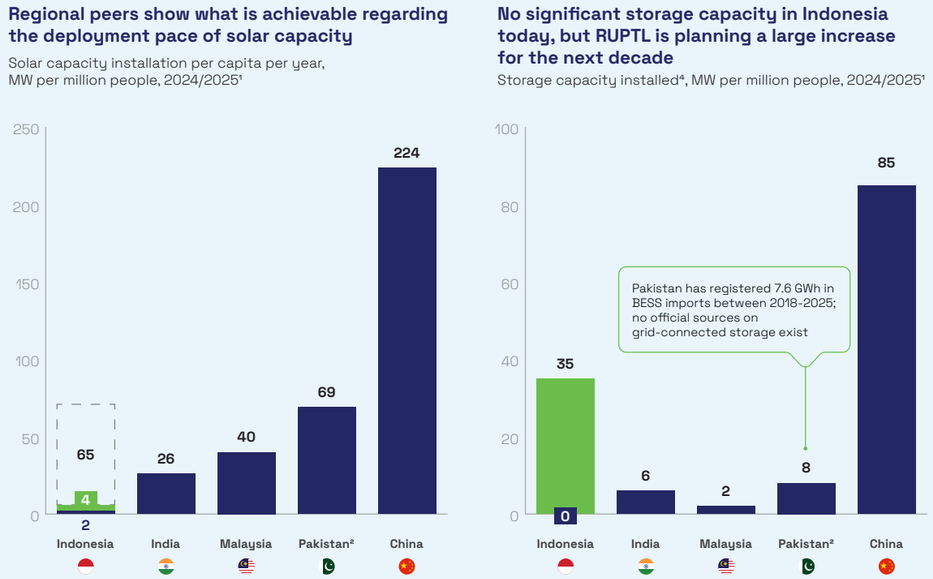


Source; World Bank (2026) Population total; IRENA (2026) Renewable Capacity Statistics 2026.

84 ESDM (2026) Handbook Of Energy & Economic Statistics Of Indonesia 2025

On solar specifically, regional peers show that there is a big opportunity to speed up deployment [Figure 14]. The 2025-2034 RUPTL targets only 17 GW of on-grid solar by 2035, roughly 1.7 GW per year. India installed 38 GW in 2025 alone; China installed 315 GW in 2025 and is targeting 2,000+ GW by 2030[85]; Pakistan, with a comparable population and significantly lower GDP per capita, imported over 15 GW of solar panels in 2024 without a formal national programme[86]. Figure 14 translates these deployment speeds into capacity installed per million people per year: at 2 MW per million people, Indonesia's current pace is less than one-tenth of India's and less than one-hundredth of China's, and the increase to 4 MW per million people per year laid out in the current RUPTL does not even begin to close that gap. If the 100 GW program is taken into account, the number increases to 65 MW per million people per year, showing Indonesia is going in the right direction, although the targets seem very ambitious compared to the nation's track record.

Figure 14 | Population-adjusted solar deployment pace and installed storage capacity in Indonesia and selected countries.



Notes: 1. most recent year available used (2024 or 2025). 2. No reliable annual installation figure exists for Pakistan, totals are based on reported imports. 3. Assumes the 100 GW is realized in 5 years. 4. Includes Pumped Hydro Storage and BESS. 5. Assuming a 4-hour storage duration for all BESS systems imported. Source: Solar: Indonesia: MEMR / IESR (pv magazine, Feb 2026); India: MNRE (pv magazine, Jan 2026); China: NEA (pv magazine, Jan 2026); Pakistan: Ember / WRI (2025); Malaysia: IEA-PVPS (2026). Storage: China: CNESA (2024), China Daily / State Grid (2025); India: PV magazine (2026); Malaysia: Energy-Storage.News (2025); Pakistan: IEEFA (2025), PV Magazine (2026); Indonesia: IESR / PLN RUPTL (negligible operational storage). Population: UN WPP 2024.

85 PV Magazine (2026) China adds 315 GW solar in 2025
86 No reliable installation statistic exists for Pakistan; import data is the best proxy.

Storage deployment shows a comparable gap. Indonesia's operational grid-scale electricity storage (i.e. PHS or BESS) remains at pilot scale[87], while regional peers are scaling rapidly: Pakistan imported 7.6 GWh of BESS capacity between 2018-2025, and saw a tripling of imports between 2024-2025[88]. India is moving even faster: it added 4.6 GWh of BESS capacity in the first quarter of 2026 alone, and installed capacity reached 8.5 GWh by mid-2026[89]. Without accelerating storage build-out, Indonesia risks underutilising its abundant renewable resource base.

2.3
Renewable generation costs are approaching parity with new-built coal, but remain above the marginal costs of existing coal plants

Indonesia's power system relies on a mix of generation technologies that differ in cost and system role. Coal-fired power generation dominates the current generation mix and provides baseload power at low cost under the Domestic Market Obligation (DMO) [see Box E] at a capped fuel price of USD 70 per tonne, the marginal generation cost of existing coal plants is around 3.5 cts/kWh. Without DMO pricing, new coal-fired power generation would cost around 8 cts/kWh. Gas provides flexible, dispatchable capacity, but at higher cost than coal [Figure 15].

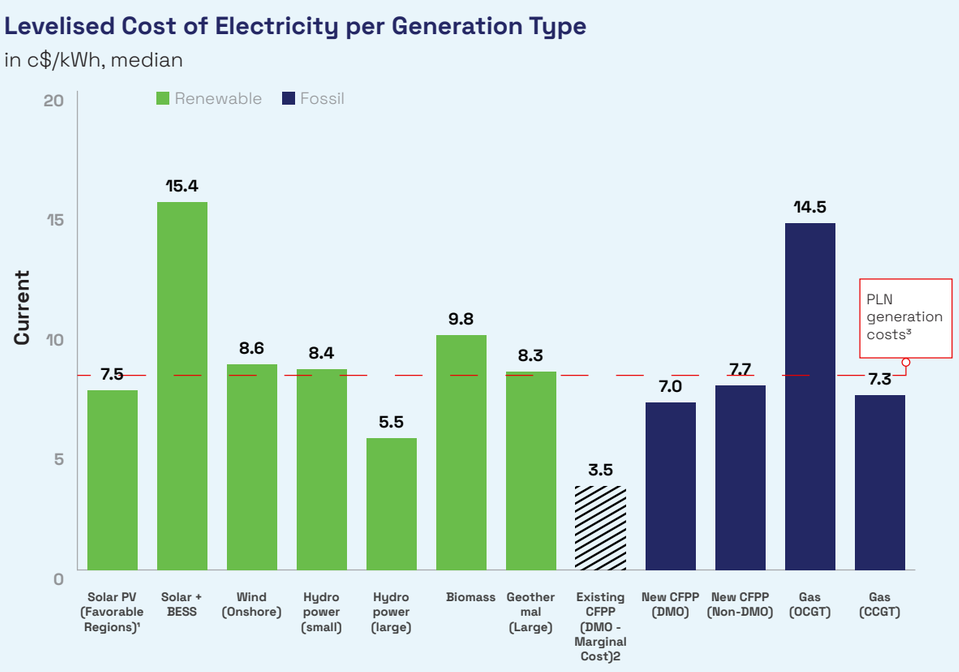
Indonesia's power system relies on a mix of generation technologies that differ in cost and system role.

Renewables span a wider cost range, reflecting differences in resource quality, project scale, and site characteristics. Hydro and geothermal are firm, low-carbon technologies and play an established role in Indonesia's mix today, but both are constrained by site availability and long development timelines. New geothermal projects deliver power at around 8 cts/kWh and new hydro projects at around 6-8 cts/kWh, both above the marginal cost of running existing coal plants. Solar generation can already be delivered at around 5-10 cts/kWh, with the lower end of the range in favourable locations, with the median of 7.5 cts/kWh broadly comparable to new non-DMO coal. Wind is more limited in scope and currently delivers power at around 9 cts/kWh in Indonesia's better wind-resource locations.

Renewables span a wider cost range, reflecting differences in resource quality, project scale, and site characteristics.

87 At the time of this report's publication, only one grid-scale BESS was operational; 14 MWh at the IKN's 50 MW Solar PV Project.
88 PV Magazine (2026) Pakistan imports 4.6 GWh of BESS in 2025
89 Mercom India (2026) India adds 4.6 GWh of Battery Energy Storage Capacity in Q1 2026

Figure 15 | The cost of renewable generation is still higher than running existing coal plants



Notes: 1) Favorable regions incl. Java, Sumatra; 2) Marginal cost includes fuel cost and variable O&M; 3) Biaya Pokok Produksi (BPP) based on PLN Statistics 2023; 7) Based on last reverse auction result in Q4 2025

A standalone comparison between any of these technologies and coal also understates the full cost of integration. Coal plants generate around the clock; solar and wind generate only when the resource is available. A fair comparison therefore requires variable renewables to be paired with battery energy storage (BESS), which can shift daytime solar generation into the evening demand peak and provide firmer capacity. Solar generation combined with battery energy storage systems (BESS)[90] can deliver power at around 15 cts/kWh today, significantly above current fossil generation costs[91]. Battery costs are falling rapidly, however, and the gap is narrowing (see Chapter 3).

90
91 Based on a 4-hour duration storage system and top-down modelling, no project-level data is available as only one utility-scale solar + storage project is operational so far in Indonesia (as of Sept 2026).

BOX E | Domestic Market Obligation

Indonesia operates a **Domestic Market Obligation (DMO)** that requires coal mining companies to sell **at least 25% of their annual production domestically at a fixed price**, primarily to power plants operated by the state utility PLN.

Coal supplied under the DMO is subject to a **Domestic Price Obligation (DPO)**, which caps the price of coal sold domestically. For power generation, the price is capped at **USD 70 per tonne**, while selected industrial users face a cap of **USD 90 per tonne**. These regulated prices are often **well below international coal market prices**, particularly during periods of high global commodity prices. By capping fuel costs for coal-fired power plants, the DMO–DPO system **lowers the effective cost of coal-based electricity generation** relative to market-based fuel prices. Using today's coal export prices, the DMO brings down the marginal price of coal-fired power generation by existing coal-fired power plants by ~30%, from ~USD 5 cts/kWh to USD 3.5 cts/kWh[92].

The system therefore functions as an implicit subsidy to coal-fired power generation, shielding the electricity system from global coal price volatility and helping stabilise electricity tariffs. At the same time, it affects price signals in the power sector, as coal-fired power generation appears cheaper than it would under market-based fuel prices.

92 Based on the difference between the DPO of $70/t and the average official benchmark coal price for the same grade coal in Q1 2026 ($103.6/t), and assuming a 35% efficiency for existing coal plants. Source: ESDM, Harca Acuan.

2.4 First-mover utility-scale projects show what is possible, but cost-competitiveness remains challenging

The feasibility of utility-scale renewables under Indonesian conditions has been demonstrated in practice. Projects such as **PLTS Cirata**, **PLTS Kota Bukit Indah**, **PLTS IKN**, and **PLTS East Bali** show that utility-scale solar installations can be financed, permitted, and delivered within commercially viable timelines [Figure 16].

These strategic projects succeeded because a specific set of enabling conditions was in place, conditions that are still not systematically available across the wider market (Figure 16). Common success factors included early access to suitable land, timely confirmation of grid connection, alignment with national or regional development priorities, clear long-term offtake arrangements, and strong strategic partnerships between local and international developers or investors. Where these conditions align, renewable projects can move from concept to operation relatively quickly (i.e., 1-2 years for solar, see **Error! Reference source not found.**).

However, in most cases these have remained strategic or first-mover projects, rather than triggering broad-based market replication. Commercial scalability remains the core challenge:

several developers have been able to advance one successful solar project, but follow-on projects remain difficult to justify because project economics are still weak relative to achievable market prices. Project economics are highly impacted by regulatory hurdles, experts within the industry have cited greater regulatory certainty as an important lever to increases developer interest and project economics, while reducing perceived project risk. This is particularly important in a market where project costs remain high, driven by module and balance-of-system cost (elevated by local content requirements), land costs, and grid connection costs (see Chapter 3 for a full breakdown).

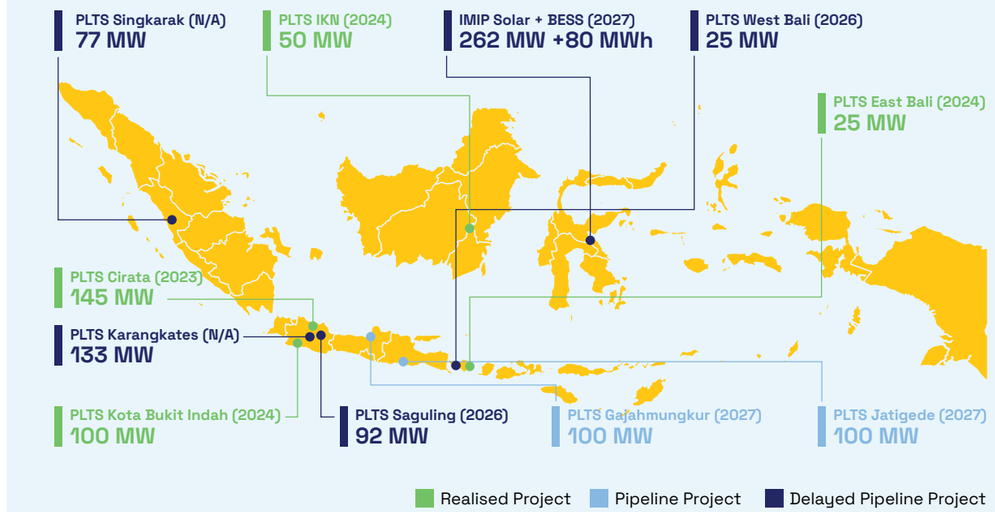
At the same time, **achievable revenues are often too low to support attractive returns**. Three structural factors are particularly important. First, the Domestic Market Obligation price cap keeps domestic coal prices well below international market levels, reducing the effective cost of coal-fired power generation by around 30%, from approximately 5 to 3.5 cts/kWh (see Box E). This suppresses the benchmark against which renewable projects compete, creating a structurally uneven playing field for unsubsidised developers. Second, the tariffs PLN is typically willing to offer to independent power producers fall below the level required to make solar projects commercially viable, particularly where development costs are elevated by land constraints, permitting complexity, or local content requirements. Third, most of coal-fired power plant (CFPP) PPAs have a take-or-pay clause, whilst previous solar PV-based PPAs have an Annual Contracted Energy (ACE) that caps sold electricity to the system, favoring CFPPs in the dispatch order.

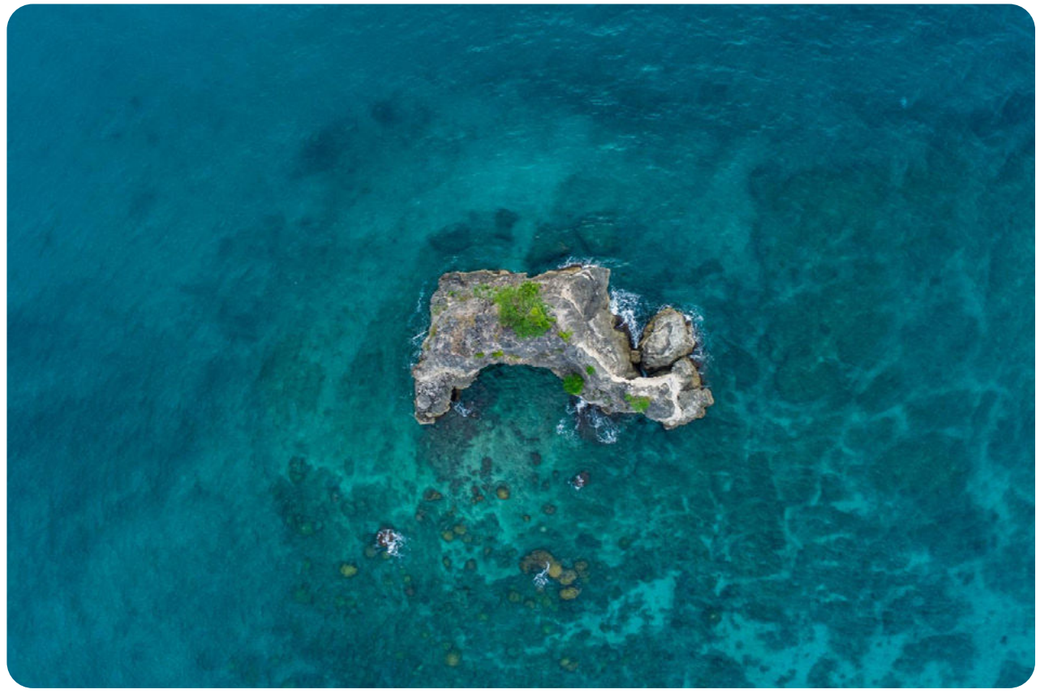
Policy and regulatory uncertainty compounds both problems. Procurement processes are unpredictable, and bankable offtake routes outside PLN remain limited. Together, these factors compress the revenue that renewable projects can earn, making follow-on investment difficult to justify even where technical potential is strong.

As a result, Indonesia is stuck in a low-volume equilibrium:

> **Projects do not scale because economics are weak, and economics remain weak because the market has not yet scaled.**

Figure 16 | Case studies of utility-scale Indonesian solar projects.





List of Realised Solar Projects and Their Enablers

	Solar Projects	Enablers
Realized Projects	**PLTS Cirata**	• Strategic partnership between foreign investor (Masdar) and PLN that unlocks international capital and expertise. • Designated as National Strategic Project (PSN), which fast-tracked regulatory approvals and given priority support. • Long-term PPA with PLN.
	PLTS Kota Bukit Indah (Industrial Estate)	• 80 hectares of industrial estate land secured early, located inside the Kota Bukit Indah Industrial Estate. • Clear industrial offtake, the plant directly aligns solar generation with local industry demand.
	PLTS IKN Solar + BESS	• Early land and grid connection secured. • High political support, tied to national development priority (net-zero emission capital city) and President's vision. • Strategic partnership between Sembcorp and PLN.
	PLTS East Bali	• Long-term PPA with PLN, provides commercial certainty. • Strategic corporate collaboration between Medco Power Indonesia and Solar Philippines. • Enabling local government policies.

Cross-project Enabling Themes

- Strategic partnership with foreign and local investors
- Early securing of land/site control
- Early grid access and interconnection
- Alignment with government strategic vision and policies
- Clear long-term power offtake or demand assurance

Sources: PLN (2023, 2024); PwC (2025); Medco (2025); Systemiq Analysis.



List of Pipeline Solar Projects and Their Status & Blockers

	Solar Projects	Enablers
Delayed Pipeline Projects	**PLTS Karangkates**	• Space clearing conflicts with local fish farmers • Initially planned to be operating in 2025, but developers currently (re-)assessing land used and social impact
	PLTS West Bali	• Initially planned during G20 Summit Bali in 2022 • Land clearing issue delayed the development
	PLTS Singkarak	• Space clearing conflicts with local fish farmers, concerns that PLTS will affect the population of local fish
	IMIP Solar + BESS	• Long permitting and negotiation process, has been in discussion since 2022
	PLTS Saguling	• Long permitting and negotiation process, tender process started in 2019 and reached financial close in 2025 • PLTS Saguling is expected to operate in 2026
Pipeline Projects	**PLTS Jatigede**	• Still in pre-development stage • Commercial structure not finalized
	PLTS Gajahmungkur	• Strategic international organizations developers (ADB and AIIB) • Detailed environmental and social impact to reduce community concerns on social issues.

Cross-project Blockers

- Uncleared land/space leads to social conflicts and delays
- Long permitting and negotiation process

Notes: These projects are currently ongoing and still in development phase. Both projects are planned to be operated in 2027.

Sources: PLN (2022, 2025); Times Indonesia (2025); Kabupaten Malang (2025); PwC (2025), Bisnis.com (2025), Nickel Industries (2023); Systemiq Analysis.



2.5 Indonesia's ambition is now accelerating: the 100 GW solar programme

Indonesia's solar ambition is now accelerating, as signalled by the 100 GW solar programme. In August 2025, the government announced a target of 100 GW of solar PV deployment by 2030, targeting a mix of off-grid deployments for remote areas, rooftop solar and grid-scale projects. Compared with the previous RUPTL target of just 17 GW on-grid solar by 2035, this represents a step change in ambition. As Figure 14 shows, delivering this programme within five years would bring Indonesia close to Pakistan's current deployment pace, a significant change from today.

Indonesia's solar ambition is now accelerating, as signalled by the 100 GW solar programme.

The near-term push is significant. For utility-scale projects, only around 6 GW of on-grid solar is currently included in the RUPTL before 2030, suggesting that full delivery of the 100 GW programme would represent a massive increase in solar deployment versus current RUPTL plans. It would also mean an almost doubling of Indonesia's generation capacity by 2030 (from 96 GW in 2024).

While the design and composition of the full 100 GW programme are still being finalised, previous IESR analysis identified around 20 GW of decentralised solar that could have near-term impact before 2030, mainly by replacing diesel generators (de-dieselisation) and improving electricity access in remote regions[93].

93 IESR (2026) The Solar Archipelago: Indonesia's 100 GW Leap to Energy Sovereignty

Whether 100 GW is achievable by 2030 depends on two mutually reinforcing conditions:

- **On the supply side,** the pace at which solar and battery projects can be brought down to compete with existing coal-fired power generation. Physical deployment capacity exists; the binding constraint is cost competitiveness [see Chapter 3].
- **On the demand side,** sufficient and timely electricity demand growth to absorb the additional generation without curtailment risk. As Chapter 1 shows, accelerated electrification across industry, transport, and residential sectors, combined with new demand from electricity exports and data centres, could generate an additional 180 TWh of demand by 2035 compared to BAU, helping create room for more on-grid solar generation.

Box F | Electricity demand might triple long-term

Over a longer horizon, the demand-side question is more about timing than about stranding risk. The Energy Transitions Commission projects that global electricity demand will roughly triple by 2050 as transport, heating, industry, and hydrogen production shift onto the grid, and Indonesia's trajectory will follow the same logic[94]. Today's solar additions are therefore not at risk of outpacing future demand. The challenge is to align supply build-out with demand growth, and to use catalytic demand sources to underwrite early projects until broader demand catches up.

94 ETC (2025), Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems

The two conditions reinforce each other. Faster electrification supports more solar by absorbing additional generation; cheaper solar accelerates electrification by lowering the cost of switching from fossil-based technologies. The case for moving quickly has been strengthened further by the 2026 Iran conflict, which pushed oil prices above USD 100 per barrel, making the economics of replacing diesel generators with solar and batteries more compelling than ever and exposing the fiscal cost of Indonesia's continued oil import dependence (see Chapter 5).

The two conditions reinforce each other. Faster electrification supports more solar by absorbing additional generation; cheaper solar accelerates electrification by lowering the cost of switching from fossil-based technologies.

Getting the policy response right matters as much as the headline ambition. Without targeted interventions to bring down solar costs, the 100 GW programme risks driving up overall system costs; without parallel action to scale demand and storage, additional solar capacity could face curtailment as supply outpaces what the system can absorb. The enabling conditions required to deliver on both fronts are set out in Chapter 6; if the government's 2030 timeline is to be met, those interventions need to be pursued with urgency.



Chapter 3

Solar's path to cost-competitiveness in Indonesia

Chapter 2 showed that Indonesia has abundant solar resources, but that commercial deployment is stuck in a low-volume equilibrium. This chapter examines the current economics of solar in Indonesia. It shows that there is a large cost gap with leading markets, driven by addressable cost components, not fundamental constraints. The gap is largely explained by elevated module and balance-of-system costs (driven by local content requirements), high land and grid connection costs, and unpredictable permitting and financing. With targeted action on each component, Indonesia's solar LCOE could fall by 30-50% versus today's level by 2035, from 5-10 cts/kWh to 4-7 cts/kWh, approaching the levels already achieved in leading markets.

The chapter is structured in three sections. Section 3.1 sets out the global solar and battery revolution that has reset what is possible. Section 3.2 diagnoses the cost gap between Indonesia and leading solar markets, breaking it down into specific addressable components. Section 3.3 sets out how each cost component can come down, and at what pace.

3.1
The global solar and battery revolution is happening now

The most significant energy development of the past decade is the dramatic global reduction in the cost of solar PV and batteries, faster and further than any prior projection. Since 2010, global solar PV module costs have declined by around 20% per year, and battery system costs by an average 16% per year, driven by technical innovation, manufacturing economies of scale and learning curve effects [Figure 19].

These cost declines are transforming the economics of electricity systems. **In many regions, solar is already among the cheapest sources of new-build generation**, reflected in BNEF's latest global benchmark LCOEs of around 4 cts/kWh for solar PV, compared with 7.8 cts/kWh for coal-fired power generation and 10 cts/kWh for gas generation (CCGT)[95]. **Batteries are the second half of this shift, and their economics have moved even faster over the last two years.** BNEF's global benchmark cost for a four-hour battery project fell 27% year-on-year to 7.8 cts/kWh in 2025, a record low, and BNEF projects a further 25% reduction by 2035[96]. Cheap batteries mean solar generation can be stored and shifted into evening demand periods at low incremental cost, while power systems remain their reliability.

Together, solar and batteries are becoming the default option for power system expansion in sun-belt countries. In 2025 alone, developers commissioned around 87 GW of co-located solar-and-storage projects globally, delivered at an average of around 5.7 cts/kWh. Recent auctions

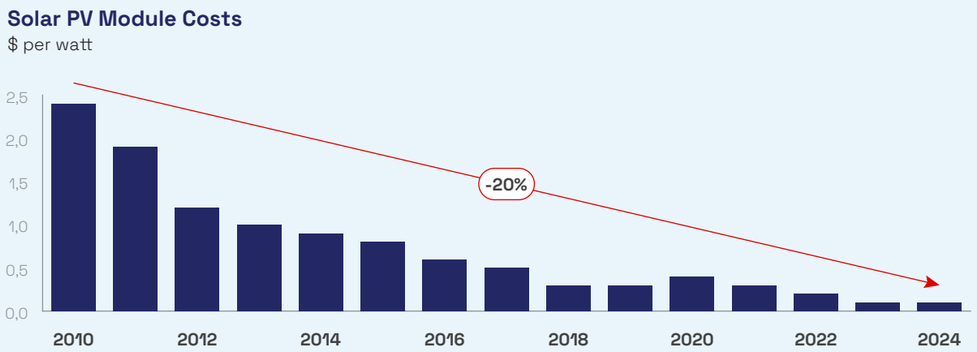
Together, solar and batteries are becoming the default option for power system expansion in sun-belt countries.

95 BNEF (2026) Battery Storage Costs Hit Record Lows as Costs of Other Clean Power Technologies Increased: BloombergNEF
96 BNEF (2026) Levelized Cost of Electricity 2026

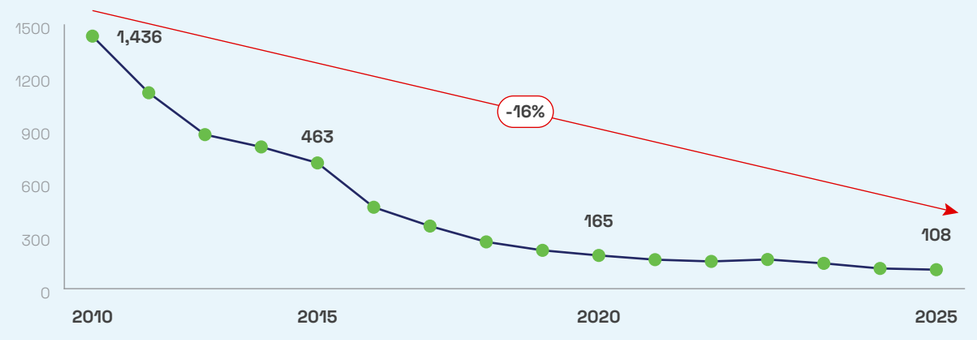
confirm the trajectory: Saudi Arabia is procuring 5 GW/20 GWh of battery storage in dedicated tenders alongside solar tenders clearing near 1.3 cts/kWh, and India's first solar-plus-six-hour-battery auction, in early 2026, cleared at around 3.4 cts/kWh[97]. The combination delivers both low-cost electricity and reliable supply outside daylight hours, at prices competitive with, and often below, new fossil generation.

For sun belt countries[98] such as Indonesia, with strong solar irradiation and large resource potential, this revolution represents an extraordinary opportunity. Yet Indonesia's current solar costs sit well above leading-market levels. The remainder of this chapter sets out where the gap comes from and how it can be closed.

Figure 17 | Overview of the main electricity supply scenarios used in this report: BAU (RUPTL) and least-cost, and the combination with demand scenarios.



Note: Module element of benchmark capex for a typical fixed-axis utility-scale PV project.
Source: BNEF (March 2025), Solar Modules Are Cheap and Will Become Even Cheaper



Source: BNEF (2025), Lithium-ion battery price survey December 2025

97 Chambers and Partners (2026) Power Generation, Transmission & Distribution 2026 – Middle East

98 As described in the ETC's 2025 Power Systems Transformation report, sun-belt countries are characterised by high solar resource (and therefore a high share of solar relative to wind in generation) and consistent seasonal demand (leading to mostly daily balancing patterns, rather than the seasonal balancing patterns found in, for example, north-western Europe).

3.2
Indonesia's solar LCOE is above leading-market levels due to addressable cost components

As discussed in Chapter 2, solar PV already stands out as Indonesia's most promising renewable technology: large resource potential, short build times, and globally falling costs. The question is how close solar is to being commercially competitive at scale, and what it would take to close the remaining gap.

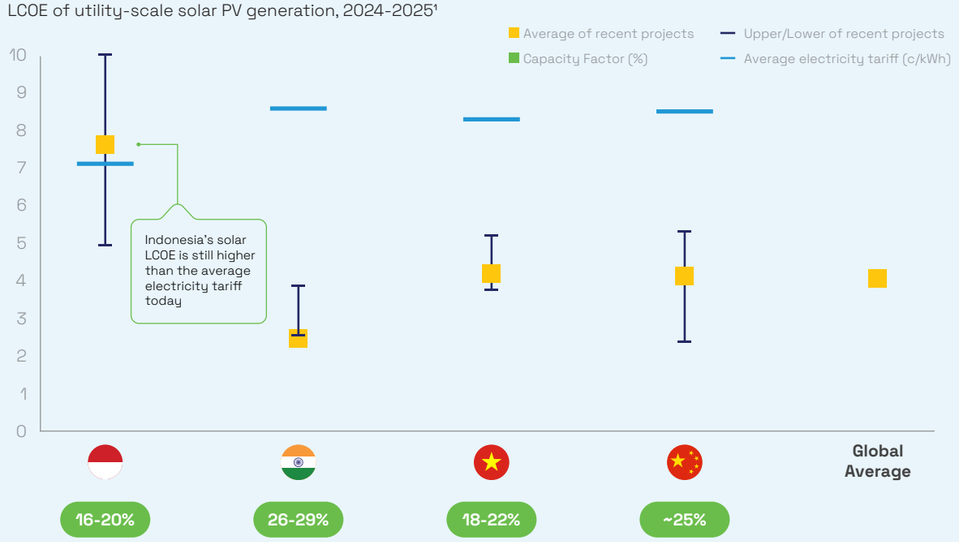
Indonesian solar electricity can already be delivered around 5-10 cts/kWh, which, as Chapter 2 demonstrated, can be broadly comparable to new non-DMO coal-fired power generation but still significantly above the marginal cost of existing DMO coal-fired power generation. Note that coal-fired and solar generation cannot be compared fully like-for-like: coal generates round-the-clock, whereas standalone solar generates only during daylight hours. Solar can be paired with battery storage (BESS) to firm up supply and shift generation into the evening, though this adds to cost: as shown in Chapter 2, Solar generation combined with battery energy storage systems (BESS) can deliver power at around 15 cts/kWh today, significantly above current fossil generation costs[99].

Indonesian solar electricity can already be delivered around 5-10 cts/kWh, which, as Chapter 2 demonstrated, can be broadly comparable to new non-DMO coal-fired power generation but still significantly above the marginal cost of existing DMO coal-fired power generation.

The more important reference point, is what leading solar markets have already achieved in terms of levelised cost. China and Vietnam can deliver solar generation for around ~5 cts/kWh [Figure 18]. India has even reached around 3 cts/kWh for standalone solar generation and around 4.5 cts/kWh for solar with batteries on an almost round-the-clock basis [See Box F]. All of these leading solar markets, also have one thing in common: the levelised solar cost is under the electricity tariff, reducing the inertia of deployment in the system. For Indonesia, the gap between peers, and the gap against the current average electricity tariff, is large. The strategic implication of this significant: every year Indonesia delays scaling solar, peers are locking in lower costs and more competitive industrial electricity prices.

99 This is a top-down estimate, no project-level data was available at the time of this report's publication, as

Figure 18 | Indonesia's Solar PV generation costs are high compared to regional peers and Indonesia's own electricity tariff.



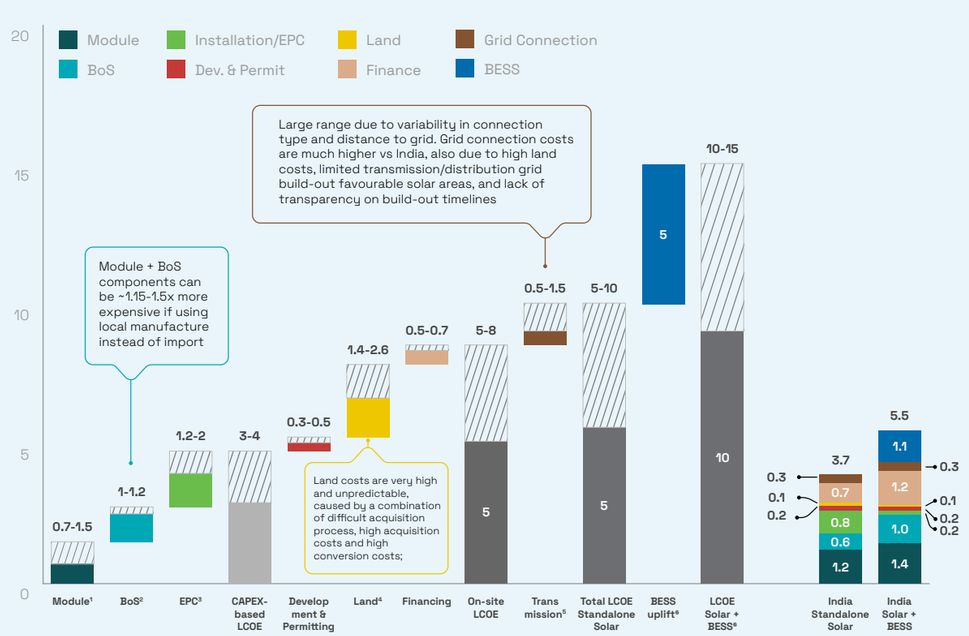
Notes: 1. Most recent year available used, 2024-2025 for most countries. India based on competitive auction outcomes, China, Vietnam based on support mechanism frameworks. Indonesia LCOE based on developer interview; 2. Lower range based on existing data in 2024, Upper range based on RUPTL 2025-2034 plans. Source: Central Electricity Regulatory Commission India (2024–2025) Solar tariff adoption orders (SECI/SJVN); National Development and Reform Commission China (2025) Renewable mechanism pricing framework and provincial results; Ministry of Industry and Trade Vietnam (2025) Decision 988/QD-BCT solar price framework; Energy Regulatory Commission Thailand (2024) Renewable FiT procurement framework; Solar Quarter (2026); Berkeley (2025) Implications of India's Solar + Storage auctions; IRENA (2025) Renewable Power Generation Costs in 2024

BOX F | Solar PV cost reductions in India

Over the past decade, delivered solar generation costs have fallen by roughly 50% in India, showing how quickly costs can fall when scale, competitive auctions, stronger supply chains, and lower financing costs reinforce one another. For 6-hour storage durations, auction prices recently dropped to $34/MWh[100]. Recent Indian auctions for almost round-the-clock[101] renewable electricity, combining solar and storage, have even achieved prices of around USD 50/MWh in nominal terms[102]. Because these contracts are typically fixed in nominal terms over long durations, the real price of electricity declines over time, reaching the equivalent of below $25/MWh in real terms by the end of the contract period in 2045. This illustrates how rapid deployment and supportive market frameworks can drive renewable electricity costs to extremely low levels.

100 Ember (2026) Battery storage is now cheap enough to unleash India's full solar potential
101 95% availability
102 Chojkiewicz et al (2025) plummeting solar+storage auction prices in India unlock affordable, inflation-proof 24/7 clean power

Figure 19 | Breakdown of current Solar PV generation cost (LCOE) components in Indonesia versus India.



Notes: 1. Survey results of 12 to 20 c/Wp, with upper range representing local manufactured prices, lower range represents import price, ex. Logistics.; 2. BoS includes inverter, electrical components, mounting or floaters (if applicable) and others. 3. Includes EPC services and civil works. Upper end of range represents remote area. 4. Based on average land price and additional land conversion cost for 5 major islands modelled in our study (Java, Sumatera, Kalimantan, Sulawesi, MPNT). High end of the range corresponds with Java, low end with Kalimantan. 5. Large range as cost depends on connection type (subsea/overland etc.) and distance to transmission grid, assumes only transmission lines, no new substation built. 6. Based on 4-hour BESS.
Source: Expert input based on actual projects in Indonesia and India.

This solar generation cost gap with leading markets is driven by three specific and addressable cost components, plus two additional factors that are smaller in cost terms but can be full project blockers in practice [**Error! Reference source not found.**]:

- **Module and balance-of-system (BoS) costs:** local content requirements restrict access to the lowest-cost global modules and components, keeping hardware costs above international benchmarks. Developers indicate that component costs vary between 12-20 cts/Wp, with the higher end of the range corresponding to locally manufactured modules, and the lower end to imported modules. The component costs part of the LCOE can be around 10-50% higher versus global benchmarks, with recent industry commentary outlining the focus to limit local prices at 15% higher than imported cells. Domestic manufacturing capacity for the required module technology exists in Indonesia, including from Tier 1 manufacturers, but differences in scale, incentives, and technology ownership mean local prices cannot yet match Chinese export levels. The Ministry of Energy and Mineral Resources (MEMR) is targeting a maximum premium of 15% over Chinese reference prices, though developers report a larger gap in practice.

- **Land acquisition costs:** land prices are high and further elevated by regulatory complexity, the absence of pre-zoned land for renewables development, and protracted acquisition processes in which developers must deal with many individual landowners. Compared to land costs in India, the land cost component for Indonesian solar projects can be ~14-26x higher.

- **Grid connection costs:** projects are often located far from the transmission network, and developers must fund initial capex for the connection themselves, building the transmission lines back to the main network and, in some cases, new substations[103]. Land acquisition challenges along transmission corridors compound these costs further, adding to their variability.

Two additional factors contribute a smaller but meaningful cost premium, and can in practice become full project blockers:

- **Development and permitting costs**, estimated at 0.1-0.3 cts/kWh higher in Indonesia than in India today. Long and unpredictable permitting timelines increase pre-construction expenditure, but more critically, absent or delayed permits can prevent projects from reaching financial close entirely.

- **Financing**. Financing costs apply to every dollar of CAPEX, so a small change in WACC translates into a meaningful change in LCOE. For example, for solar PV generation projects in India, a 1 percentage point change in the cost of capital leads to a 6% increase of the project's LCOE[104]. Beyond the cost of finance, access to finance is also a binding constraint: when procurement, permitting and licensing are unpredictable and prone to delays, projects struggle to secure financing on any terms. Limited data is available on the actual cost of financing for Indonesian utility-scale solar projects, as few projects have reached FID, so the financing cost component shown in **Error! Reference source not found.** may understate the true cost.

In practice, some cost components are also highly connected: land, grid connection, and EPC costs trade off against one another by location. Sites with low land costs tend to be remote and sparsely populated, where limited grid infrastructure drives up transmission costs and a lack of local supply chains and logistics raises EPC costs. Denser, more developed areas show the reverse: transmission and EPC costs are lower because infrastructure is already in place, but land is scarcer and more expensive. Developers note that finding sites where all three costs are low is therefore difficult, if not impossible.

In practice, some cost components are also highly connected: land, grid connection, and EPC costs trade off against one another by location.

103 Cost allocations between developers and PLN differ per project and depend on the project structure.
104 Source: Developer interview

The same addressable cost components apply to solar paired with battery storage. Solar + BESS projects in Indonesia are estimated to cost around 10-15 cts/kWh today for a 4-hour BESS system, carrying the same module, land, grid and financing premiums diagnosed above, now applied to a system that also includes storage. Globally, co-located solar and battery projects that became operational in 2025 already deliver power at an average of around 5.7 cts/kWh[105]. The cost-reduction actions that are set out in Section 3.3 below therefore apply with similar force to firmed solar as to standalone solar. As those actions bring down module, land, grid and financing costs, and as battery costs continue their steep global decline, Indonesia's gap with leading markets on dispatchable, round-the-clock renewable power narrows on a similar timeline to the standalone solar gap.

The same addressable cost components apply to solar paired with battery storage.

3.3 Indonesia's solar costs can fall significantly through targeted action on specific LCOE components

The cost components set out in section 3.2 can each be brought down through targeted action. Closing the gap will not happen automatically through future tenders or market forces alone. It is conditional on interventions across the components below, all of which need to start now. These interventions are described in detail in Chapter 6, and their intended outcomes are described here.

If delivered together, these interventions could bring Indonesia's solar LCOE from around 5-10 cts/kWh today to around 4.5-9 cts/kWh by the end of the first phase and 4-7 cts/kWh by the end of the second phase of interventions, approaching the cost levels already achieved in leading markets [Figure 20]. Beyond reducing the average, these actions also compress the wide cost range that currently exists across projects and locations, making solar viable in more places and easier to replicate at scale. After the phases outlined below, further cost reductions are likely, as the global trend for solar generation costs has been downward for the past 10 years.

Beyond reducing the average, these actions also compress the wide cost range that currently exists across projects and locations, making solar viable in more places and easier to replicate at scale.

105 BloombergNEF (2026) Levelized Cost of Electricity 2026

Figure 20 | Indicative estimate of how Indonesia's Solar LCOE could reduce with targeted interventions.

Indicative outcomes of the interventions on Indonesia's solar LCOE

$c/kWh, average high-low across five modelled areas

Balancing of local content requirements for less strategic components brings down component costs

Scale and learning through catalytic projects (e.g., on RES procurement processes) brings down development, permitting and financing costs

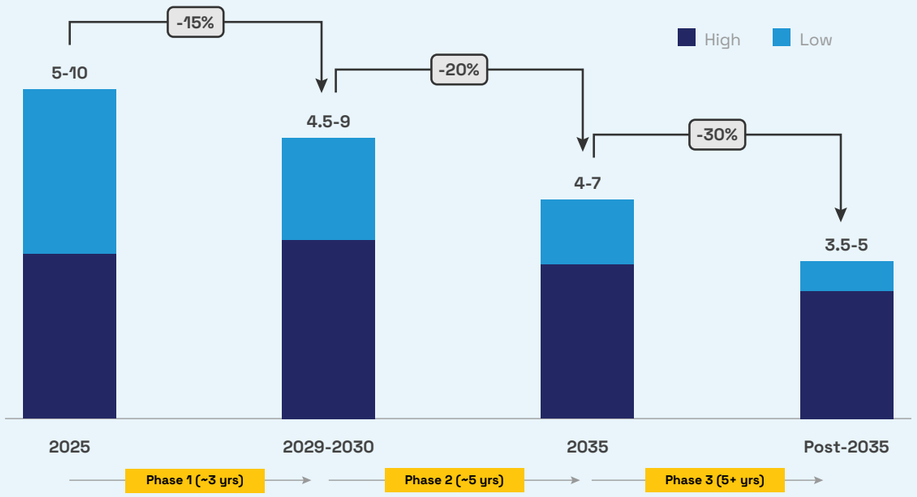
Standardized and streamlined land acquisition and grid connection brings down costs

Solar PV deployment scales (inc. RUPTL, 100 GW delivery and rooftop) supporting cost reductions across components, EPC and financing

Coordinated scale-up of domestic solar manufacturing, bringing domestic production costs in line with import prices

Continued policy support brings key cost components further down (land, grid connection)

Scale drives down EPC, financing and dev. & permitting costs



Note: Timelines are indicative and depend on policy interventions

Module and balance-of-system costs can move toward import parity through a phased local content strategy. A time-bound import exemption tied to credible domestic investment commitments would bring near-term hardware costs closer to international benchmarks, while preserving a pathway for domestic manufacturing to scale up. As domestic capacity reaches competitive volumes, local content tiers can be activated upstream (cells, then wafers and ingots). This phased approach, modelled on Indonesia's 2024 LCR relaxation (MEMR Regulation 11/2024) and India's Approved List of Models and Manufacturers (ALMM) framework, is set out in detail in Chapter 6. The near-term effect is a meaningful reduction in module and BoS costs, although MEMR (the Ministry of Energy and Mineral Resources) does not expect domestic module production to achieve Chinese prices in the near term, due to differences in production scale, incentives and technology ownership. Full effects of supporting domestic solar PV manufacturing capacity will take longer to materialize.

Land acquisition costs can be reduced through a centralised land mechanism and pre-zoning of renewable development areas. A dedicated government entity or land bank, supported by clear renewable development zones and standardised acquisition processes, would compress one of the largest cost premiums Indonesia carries today (~65-80% above India). Detailed design choices and policy steps are set out in Chapter 6. In addition, stakeholders have highlighted two viable routes to increase land available for Solar PV: first, by combining solar PV with agriculture in the form of AgriPV, and second, by re-purposing old mining areas for solar generation. Box I in Chapter 6 provides more details about these options.

Grid connection costs can be reduced by aligning transmission planning with the renewable build-out. Accelerated transmission expansion with explicit planning for renewable integration, combined with the same land-acquisition reforms above, would reduce both the cost and the accessibility of grid connection across projects.

Grid connection costs can be reduced by aligning transmission planning with the renewable build-out.

Development and permitting costs can come down through standardised procurement frameworks and a faster permitting pathway for solar. Predictable, time-bound permitting processes reduce pre-construction expenditure directly, but more importantly remove the project-blocking risk that long permitting timelines currently create. Standardised frameworks for innovative renewable procurement (including premium buyer structures and dedicated tracks for catalytic projects) further reduce transaction costs.

Financing costs come down as the broader ecosystem matures. The direct cost differential is modest, but access to finance is materially constrained by the unpredictability of permitting and licensing. As permitting reforms and bankable precedents build, projects become easier to finance on competitive terms.

These component-level reductions can be delivered through four coordinated intervention categories, set out in detail in Chapter 6. A near-term wave of fast-tracked catalytic projects (premium buyers, plus the first phase of the 100 GW programme) drives early scale, generates bankable precedent, and creates the pull that subsequent cost reductions depend on. Removing barriers to rooftop solar adds to deployment volumes across the country. Targeted policy support on land, grid, and permitting tackles the structural cost components that drive the largest portion of Indonesia's gap with leading markets. A phased local content strategy brings module and BoS costs towards import parity while progressively building Indonesian manufacturing up the value chain. The combined trajectory is shown in Figure 12; the specific actions within each category are set out in Chapter 6.

If solar costs follow this trajectory, a more renewable supply mix could meet Indonesia's demand at materially lower total system cost than the current RUPTL pathway. Chapter 4 sets out what that supply mix looks like.



Chapter 4

The supply mix opportunity: lower cost, more renewables

The previous chapters demonstrate that Indonesia's renewable build-out challenge is not one of resource availability, but of cost and scalability, and outlined a staged path through which solar generation costs could fall to competitive levels by 2035. Against that backdrop, this chapter assesses two supply-mix scenarios and the implications for system costs**.** Modelling indicates that a least-cost supply mix can deliver 10-15% lower system costs by 2035 than the 2025-2034 RUPTL pathway, with no new coal or gas additions over the period.

The chapter is structured in three sections. Section 4.1 introduces the two supply scenarios (BAU/RUPTL and least-cost) paired with the BAU and High Electrification demand scenarios from Chapter 1. Section 4.2 sets out the BAU (RUPTL) supply pathway, which delivers a gradual shift anchored in continued fossil generation. Section 4.3 sets out the least-cost pathway, integrating more renewable capacity, and compares its system-cost implications to the BAU (RUPTL) supply pathway.

4.1 Two supply scenarios

To test how different supply strategies can shape the power system and associated costs, this report models and explores two alternative supply scenarios [Figure 23]. The first is **a Business-as-Usual scenario anchored in the 2025-2034 RUPTL**, in which capacity additions, technology mix, commercial operation dates, and grid expansion follow the 2025-2034 power development plan. Project lead times are based on prevailing assumptions for conventional and renewable assets, all captive demand is assumed to be served by coal, and technology costs evolve in line with Ministry of Energy and Mineral Resources projections [Figure 22].

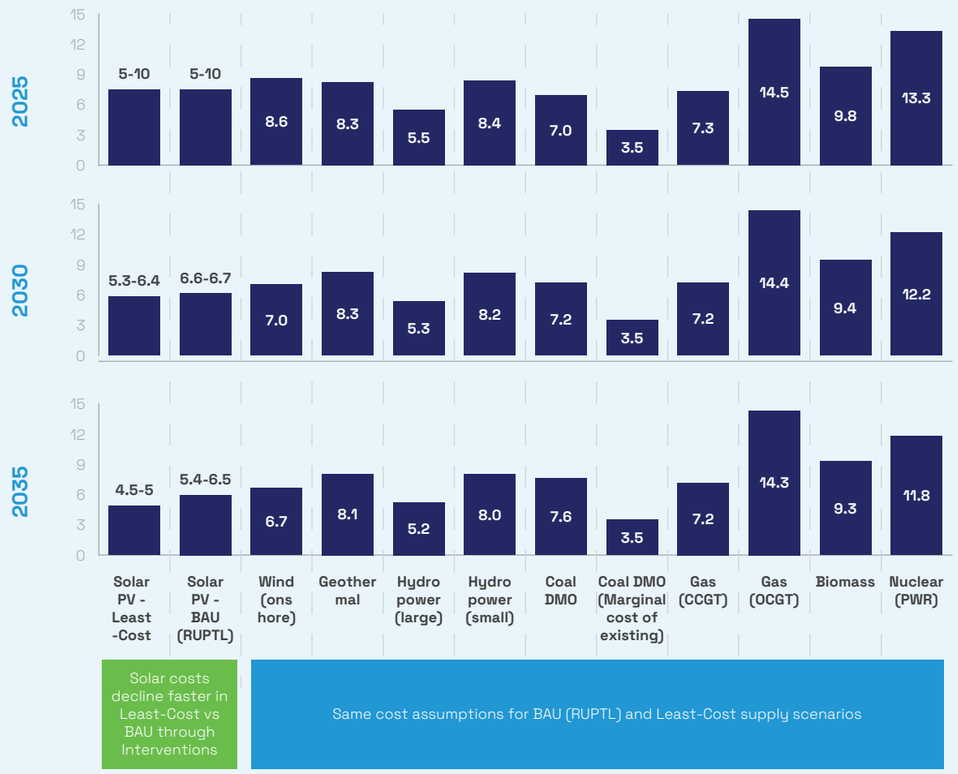
In this scenario, the build-out of capacity is technology-agnostic, allowing for unconstrained build-out where needed to meet higher demand.

The second is a least-cost supply scenario, in which the model does not follow the 2025-2034 RUPTL technology mix or build-out schedule, but instead optimises generation and associated grid infrastructure to meet projected demand at lowest total system cost while maintaining reliability under both the Business-as-Usual and the High Electrification demand scenarios. In this scenario, the build-out of capacity is technology-agnostic, allowing for unconstrained build-out where needed to meet higher demand. The cost of additional network infrastructure is included within the optimisation, and the same government cost trajectory assumptions for generation technologies are applied, except for solar, where costs decline faster over 2025-2035 to reflect the trajectory set out in Chapter 3 [Figure 22]. The Domestic Market Obligation capped price for coal-fired power generation is assumed stable across both scenarios.

Figure 21 | Levelized Cost of Electricity for main generation types in modelling.

Levelised Cost of Electricity for Main Generation Types Included in Modelling

in c$/kWh, solar costs range based on regional cost differences[1]



Notes: 1) Favorable regions incl. Java, Sumatra, unfavorable regions incl. Papua.
Source: IESR PLEXOS Model

This distinction between the 2025-2034 RUPTL-based and the least-cost supply scenario matters because the RUPTL is not designed as a pure least-cost optimisation. It is a strategic planning document that balances multiple objectives, including security of supply, policy priorities, delivery risk, existing plans and committed projects, locked-in contractual obligations, and the practical constraints of the existing system. The least-cost supply scenario is therefore not presented as a direct alternative to the RUPTL, but as a benchmark that helps assess the cost implications of the current pathway. It shows how the system could evolve if generation and grid investment were selected to minimise long-run system costs while still meeting demand and maintaining reliability. This helps distinguish between justified trade-offs and avoidable inefficiencies, especially as renewable technology costs have continued to fall faster than expected in many markets.

Figure 22 | Overview of the main electricity supply scenarios used in this report: BAU (RUPTL) and least-cost, and the combination with demand scenarios.

Specific Assumptions for Two Power Supply Scenarios

Parameter	BAU (RUPTL) Scenario Optimises power generation based on RUPTL (2025-2034) based project development capacity plans	Least-cost Scenario Optimising for least-cost power system, agnostic of technology
Power Mix	**Based on RUPTL** (Indonesia's power development plan) COD date, only **on-grid demand and supply modelled**	**Determines the generation mix for a least-cost power system**, with no constraints on which technology to build and when, only to meet total demand every year. **Only on-grid demand and supply modelled.**
Capacity buildout limit	**Based on RUPTL COD date** and **grid improvement/ development plan**	**Unconstrained build-out** to answer increased power demand, automatically building additional infrastructure. The required additional grid from RUPTL plans will be treated as a key takeaway of the model.
LCOE improvement	**Using LCOE projections** from Ministry of Energy and Mineral Resources for all generation technologies	Same as BAU, except **Solar PV LCOE improves faster with interventions**
Demand scenario combinations	Combined with **both BAU and High electrification demand**: **A** BAU demand + BAU (RUPTL) supply **B** High electrification demand + BAU (RUPTL) supply	Combined only with **high electrification demand**: **C** High electrification demand + least-cost supply



Box G | Supply scenarios cover on-grid supply only: captive demand is a significant additional opportunity

The supply scenarios modelled in this chapter cover on-grid generation only. As highlighted in Chapter 1, a significant share of Indonesia's electricity demand, 23% under BAU and 20% under High Electrification, is served by captive generation, outside the grid. In both demand scenarios, captive electricity demand grows to 150-170 TWh by 2035.

This captive demand is a significant additional opportunity for renewable deployment that is not captured the least-cost supply scenario. Industrial captive sites typically require continuous power, which solar alone cannot deliver without storage, so substitution is constrained in the near term. However, daytime industrial loads can increasingly be met by on-site solar, particularly when paired with batteries.

If solar PV were to meet 10% of captive demand by 2035, this would imply roughly 11 GW of additional solar capacity[106].This is on top of the on-grid figures modelled in section 4.2-4.3, and represents a conservative entry point for captive renewables deployment that could scale considerably higher as costs fall and storage solutions mature.

Realising this opportunity depends on the same cost-reduction actions set out in Chapter 6 that drive on-grid solar competitiveness, with one important difference: captive solar competes against the all-in cost of on-site coal or diesel generation rather than the PLN tariff.

106 Assumptions: 10% of 164 TWh captive demand met by solar at a 17% capacity factor. Note that land availability might limit actual deployment.

4.2
Business-as-Usual (RUPTL) supply across two demand scenarios

The current RUPTL build-out is sufficient to meet both demand scenarios to 2035. The same capacity additions, around 18 GW of solar PV, 8 GW of wind, 15 GW of geothermal, 8 GW of new gas, and 1 GW of new coal, are deployed between 2025-2035 under both demand cases [Figure 24**Error! Reference source not found.**][107]. 10 GW of storage is added, of which 7 GW BESS and 3 GW Pumped Hydro Storage. No additional capacity is required to accommodate the increased demand in the High Electrification [B] scenario versus the Business as Usual [A] scenario.

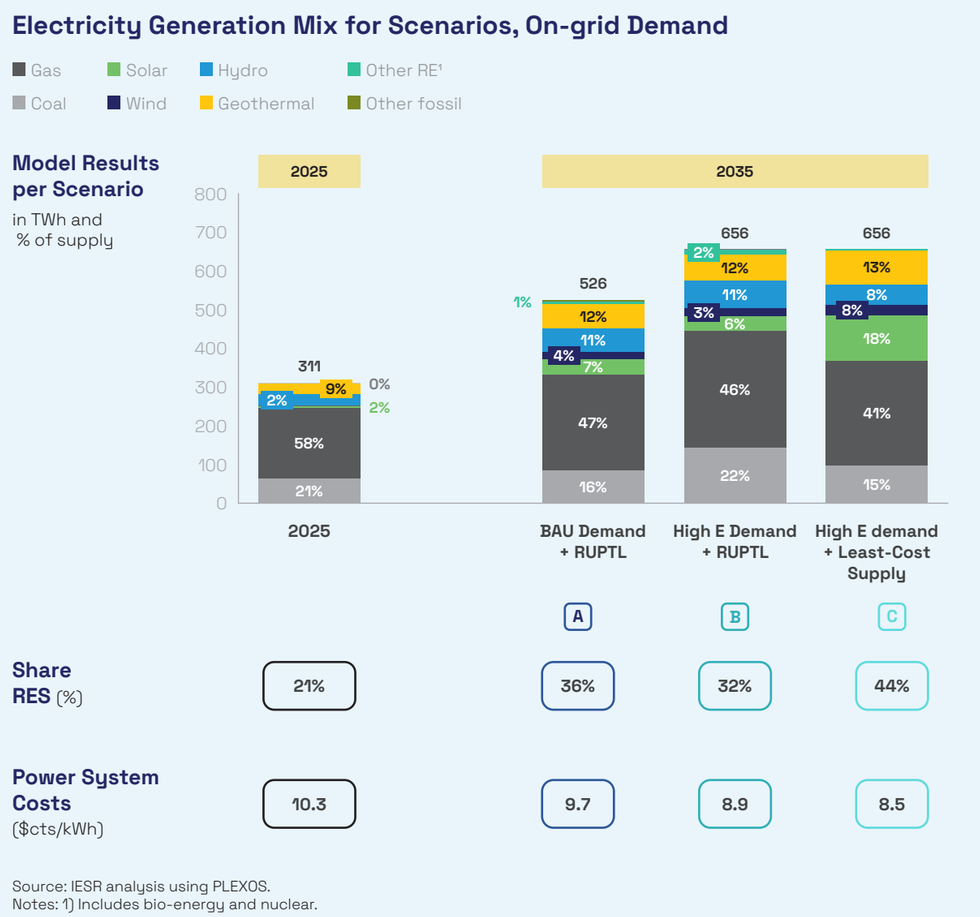
The current RUPTL build-out is sufficient to meet both demand scenarios to 2035.

107 These capacity additions are slightly higher than the RUPTL planning, which only runs for 2034. For 2034-2035, our modelling continues the supply optimization to include 2035.

The main difference between meeting the two demand scenarios is in the utilisation of the existing fossil fleet. Higher demand under High Electrification [B] is not met by building significant additional capacity, but by running existing coal and gas plants at higher load factors. As a result, the share renewable generation is slightly lower in the High Electrification demand scenario [B], falling from 36% in the BAU demand case [A] to 32% under accelerated electrification by 2035 [B], despite the same renewable capacity additions in both cases [Figure 23].

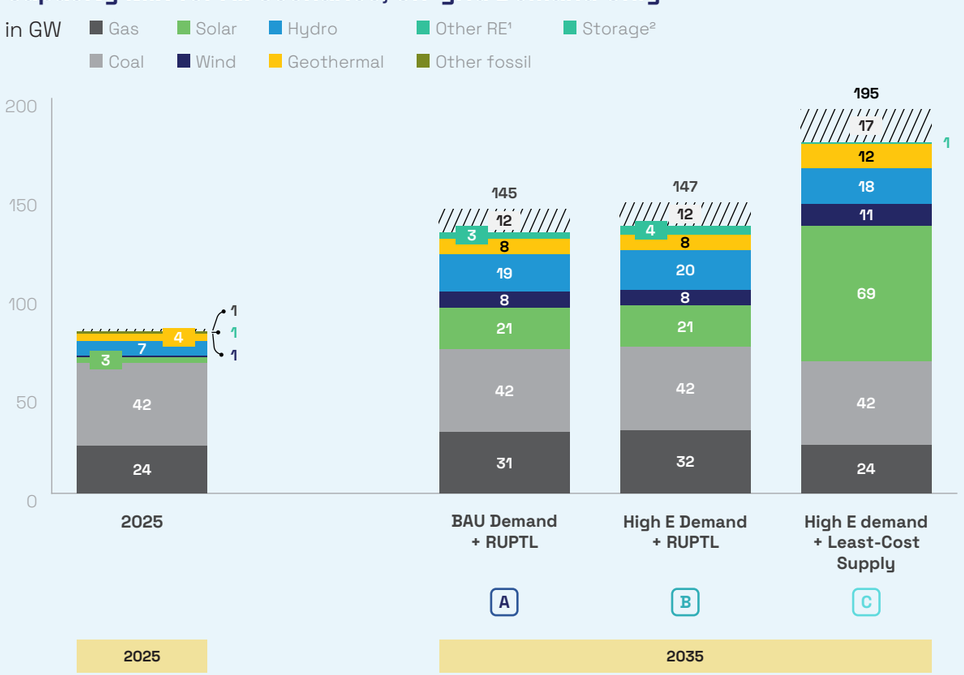
The cost impact between meeting the two demand scenarios is significant. Total system costs could fall under High Electrification, from 9.7 cts/kWh [A] to 8.9 cts/kWh [B] by 2035, as fixed capital and grid costs are spread across a larger generation base [Figure 25].

Figure 23 | The generation mix shows that scenario B meets additional High Electrification demand through increasing fossil generation, while least-cost scenario C builds out more renewables.



Source: IESR analysis using PLEXOS.
Notes: 1) Includes bio-energy and nuclear.

Figure 24 | The capacity mix shows additional demand is increasingly met by renewables by 2035 in the least-cost supply scenario.



Source: IESR modelling using PLEXOS.
Notes: 1) Includes bio-energy and nuclear. 2) Based on PHS and 4-hour BESS.

4.3 Least-cost supply across High Electrification demand

In the least-cost supply scenario, the additional demand from High Electrification can be met without building any new gas or coal capacity. The least-cost supply mix [C] adds around 65 GW of solar PV, 10 GW of wind, and 10 GW of geothermal between 2025 and 2035, alongside 17 GW of supporting storage capacity (of which 13 GW of BESS and 3 GW PHS) [Figure 24**Error! Reference source not found.**]. By 2035, the renewables share reaches 44% of total generation, compared with 32% under the RUPTL pathway under the same demand case [Figure 23].

By 2035, the least-cost supply mix consist of significantly more renewables: 44% of generation is renewable, versus 32-36% in the RUPTL supply mix. This shows that a more renewable energy system can also be a more affordable one.

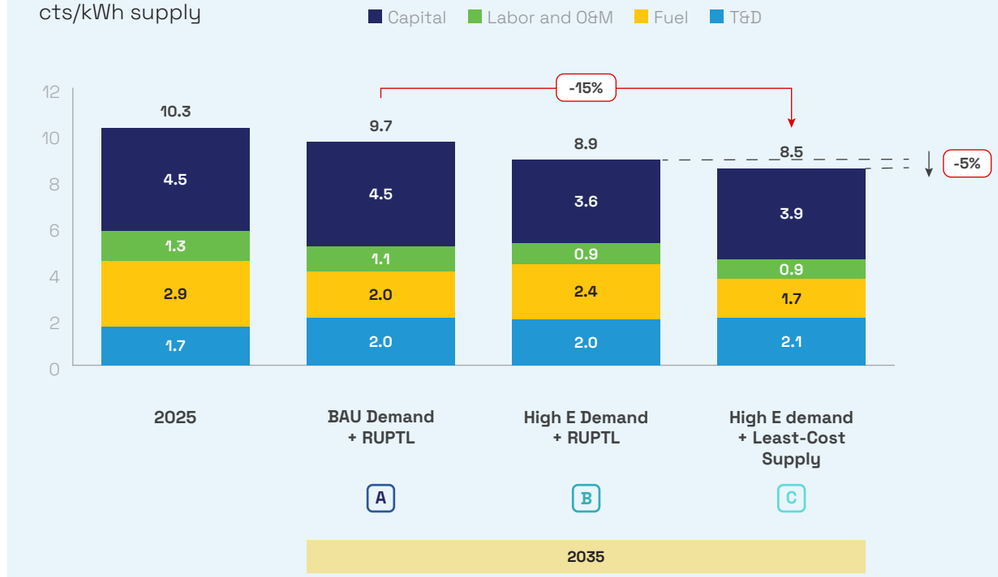
Total power system costs could fall further than under the 2025-2034 RUPTL-based pathway, reaching 8.5 cts/kWh [C] by 2035 versus 8.9 cts/kWh [B] under RUPTL with the same demand, or 9.7 cts for RUPTL and the BAU demand. Most of the savings come from lower fossil fuel consumption as cheaper solar displaces coal and gas generation.

This cost gap is conservative because it assumes coal continues to benefit from Domestic Market Obligation (DMO) prices. If the DMO were reduced or removed, coal-fired power would become more expensive, strengthening solar generation's cost advantage and widening the gap further.

A faster solar cost reduction would unlock even more deployment. In a sensitivity analysis in which the cost-reduction journey set out in Chapter 3 is accelerated by five years, on-grid solar capacity reaches around 90 GW by 2035 (versus 69 GW in the least-cost central scenario) and the renewables share rises to 26% by 2030 and 46% by 2035 [See Box: H].

Looking across the full scenario set, High Electrification combined with a least-cost supply mix delivers materially lower system costs than the BAU pathway. Total system costs fall from 9.7 cts/kWh under BAU demand + RUPTL supply to 8.5 cts/kWh under High Electrification demand + least-cost supply, a reduction of around 15% by 2035 [Figure 25]. The savings come from two reinforcing effects: a larger demand base spreads fixed capital and grid costs over more generation, and a higher share of low-cost renewables in the supply mix displaces more expensive fossil fuel generation.

Figure 25 | Total power system costs per kWh generated for all scenarios in 2035.



BOX H | How this analysis relates to the 100 GW Programme

As set out in Chapter 2, the government's 100 GW solar programme spans on-grid utility-scale, captive, and rooftop solar, with delivery targeted by 2030. Our supply scenario modelling covers on-grid supply only.

The 100 GW ambition is physically achievable: our modelling confirms the direction of travel.

The least-cost supply scenario includes around 70 GW of on-grid solar by 2035, with up to 90 GW under a sensitivity in which solar costs fall faster than the central trajectory[108]. This is a step change versus the 17 GW envisaged under the current RUPTL. When potential rooftop solar and captive deployment are added on top of utility-scale, the combined opportunity is consistent with the 100 GW ambition, particularly if cost reductions accelerate beyond the central trajectory. These scenarios do depend on two mechanisms: first, a suite of coordinated policy actions to remove barriers and bring down the cost of solar, and second, rapid electrification of Indonesia's economy, to ensure there is demand to fulfil.

The pace at which this is achieved depends almost entirely on how fast Indonesia brings down solar costs. The cost-reduction trajectory set out in Chapter 3 takes time to materialise, with moderate reductions in the early years and steeper declines arriving later as scale, learning, and supply-chain effects compound. Project development timelines also play a role: although utility-scale solar can be constructed within six months to two years (see Section 2.2), permitting, land acquisition, and grid connection processes typically add several years on top under current procedures. The modelling shows most of the solar deployment occurring in the 2030-2035 period rather than before 2030, as envisioned by the 100 GW programme.

108 All cost reductions are accelerated by 5 years in this sensitivity scenario.

Figure 26 | Solar generation capacity deployed in least-cost modelling for scenario C and two sensitivity scenarios



Source: IESR analysis. Notes: . 1. BESS and PHS. For BESS, assuming a 4-hour storage duration. 2. Scenario C assumes Solar LCOE of 4.5-9 cts/kWh in 2030 and 4-7 cts/kWh in 2035. 3. Sensitivity 1 assumes Solar LCOE of 4-7 cts/kWh in 2030 and 3.5-5 cts/kWh in 2035. 4. Sensitivity 2 assumes Solar costs reach 3.7 cts/kWh in 2027 (India's current level, adjusted for Indonesia's lower capacity factor. 5. Sensitivity 2 assumes Coal generation costs increase by 30%, to 4.5 cts/kWh for existing assets and 9 cts/kWh for new assets.

A sensitivity analysis illustrates what aggressive policy action could deliver by 2030. If two enabling conditions are met simultaneously, the modelling shows that the 100 GW programme target becomes technically achievable on its original 2030 timeline:

- **Solar generation costs fall to leading-market levels immediately.** Under this sensitivity, Indonesia's solar generation cost reaches around 3.7 cts/kWh[109] by 2027. Reaching this cost level as soon as next year will require far-reaching policy interventions, implemented with urgency.

- **The playing field with coal generation is leveled.** Under this sensitivity, coal generation costs rise by 30% from current DMO-supported levels, removing the structural cost distortion that today gives coal an artificial advantage over solar.

Under these combined conditions, the least-cost modelling **indicates more than 60 GW of on-grid utility-scale solar capacity can be deployed by 2030 [Error! Reference source not found.].** When combined with the significant (off-grid) rooftop and captive solar potential discussed in Chapter 2, the total opportunity can reach or exceed the government's 100 GW target on its original 2030 timeline.

Two readings of the 100 GW ambition therefore emerge. First, the scale is well calibrated to what is technically and economically achievable: the modelling supports the direction of travel, and 60-90 GW on the utility-scale side plus rooftop and captive could deliver on the 100 GW ambition. Second, hitting 100 GW by 2030 (rather than 2035) depends critically on how quickly policy action brings down costs. Faster cost reductions pull deployment forward; without them, most deployment lands in the 2030-2035 window.

Two readings of the 100 GW ambition therefore emerge.

109 Based on the LCOE seen for utility-scale Solar PV projects in India today, corrected for Indonesia's lower capacity factor compared to India.





Chapter 5

A more electrified, more renewable Indonesia delivers stronger economic outcomes

A more electrified economy, served by a more renewable power system, can contribute meaningfully to Indonesia's growth ambitions. **The High Electrification, least-cost scenario can represent around 7-8% of the additional GDP growth Indonesia needs** to move from its current 5% annual growth rate to the 8% ambition by 2030 [Figure 27]. Between 2025-2035, this represents around USD 160 billion of additional GDP versus business-as-usual, built from two direct GDP components: approximately USD 25 billion in additional "future-proofing" investments across the energy system, electrification, and clean manufacturing, combined with USD 13 billion in investments in data centres and electricity export projects, and approximately USD 125 billion in additional net exports from reduced oil and diesel imports and the new regional electricity exports revenue stream.

Figure 27 | Summary of direct economic effects of the high-electrification, least-cost pathway versus business-as-usual.

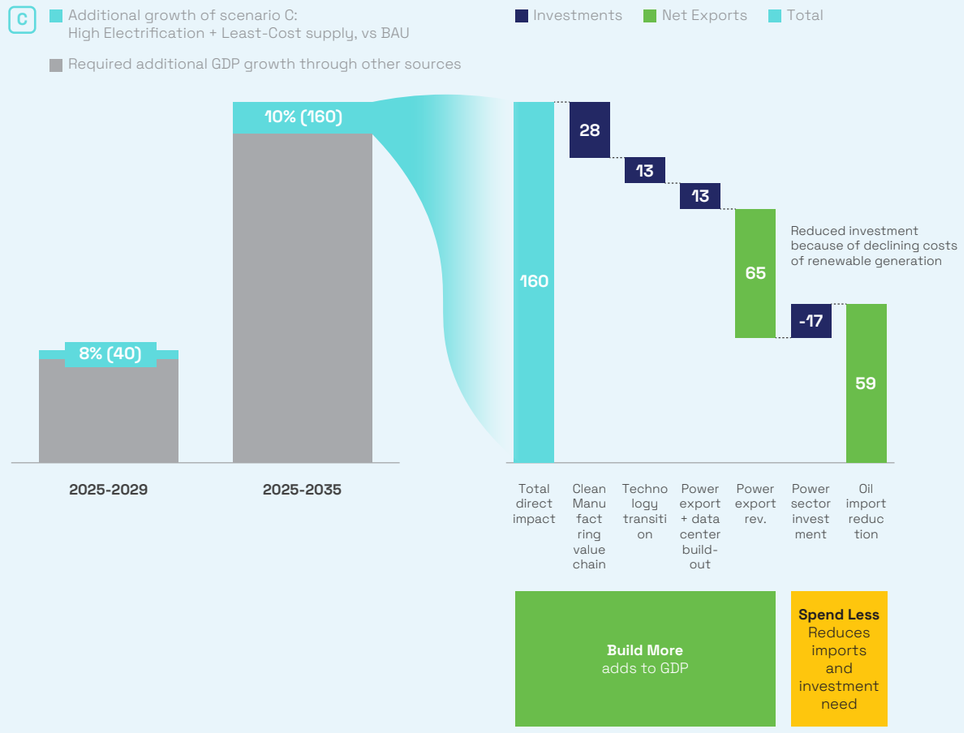
Illustrative Comparison | High-Electrification, Least Cost Pathway Could Represent-8-10% Of Indonesian's Required Additional GDP Expansion 8% Growth Pathway, In Addition To Indirect Impact

Direct impact of High-Electrification and least-cost supply scenario vs Required GDP Growth

Additional GDP growth required per year to move from 5% annual growth to 8% annual growth, $ Billion

Breakdown of additional GDP impact of High-Electrification and least-cost supply scenario vs BAU

C vs A Total change, 2025-2035, $ Billion



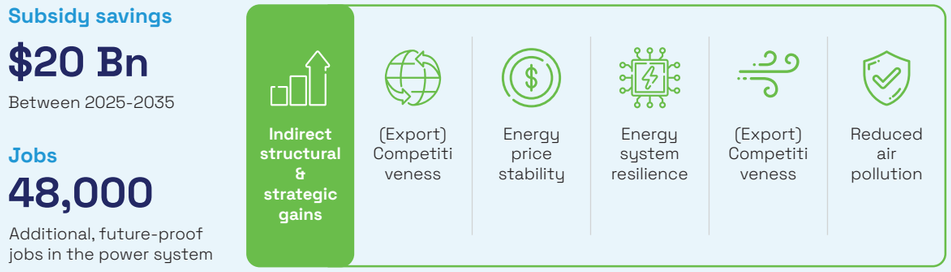
Source: INDEF Analysis

The direct GDP impact figures in this chapter capture the approximate impact of the high electrification, least-cost scenario through additional investment and additional net exports versus business-as-usual. Spillover effects that are likely to be material but are not modelled directly include manufacturing job multipliers, induced consumption from wage growth, foreign direct investment beyond the named sectors, and avoided health and environmental costs. The 8-10% figure should therefore be read as a conservative contribution, not a ceiling. It is also a contribution to growth, not a substitute for the broader policy and investment agenda Indonesia is pursuing to deliver the 8% GDP growth ambition.

Beyond these direct GDP effects, higher electrification and a more renewable power system can free fiscal space through lower fossil fuel subsidy expenses (around USD 20 billion between 2025-2035), create around 48,000 future-proof jobs by 2035, and provide structural gains for sustained growth: stronger industrial competitiveness in a greening global economy, reduced exposure to energy price volatility, greater resilience to supply shocks, and improvements in public health, air quality, and climate credibility [Figure 27].

Beyond these direct GDP effects, higher electrification and a more renewable power system can free fiscal space through lower fossil fuel subsidy expenses (around USD 20 billion between 2025-2035), create around 48,000 future-proof jobs by 2035.

Figure 28 | Indirect economic effects of the high-electrification, least-cost pathway versus business-as-usual.



Source: INDEF Analysis

The chapter is structured in three sections. Section 5.1 sets out the direct GDP impact through net exports, including the reduction in oil imports that is the single largest fiscal and economic benefit of the pathway. Section 5.2 sets out the direct GDP impact through additional investment, split into green investment across the energy system, electrification, and clean manufacturing and investment in new growth sectors data centres and power export. Section 5.3 sets out the indirect economic gains: fiscal space from reduced subsidy outlays, future-proof job creation, and the structural and strategic gains that reinforce the case for a more electrified economy and more renewable power system.

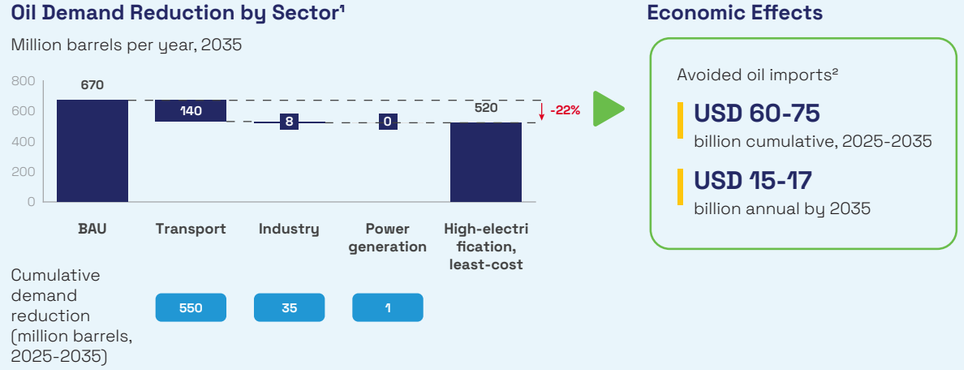
5.1 Direct GDP impact: additional net exports through reduced oil imports and electricity export

The High Electrification, least-cost pathway delivers around USD 23 billion in additional net exports per year by 2035 versus BAU, through two channels: reduced oil imports (around USD 15 billion per year, the largest component) and regional electricity exports (around USD 8-9 billion per year). The reduction in oil imports also drives a related fiscal benefit through lower subsidy expenses, which is set out separately in Section 5.3.

5.1.1 The reduction in oil imports is the largest single fiscal and economic benefit of the pathway

Indonesia's oil dependence is a structural fiscal vulnerability. Indonesia is a net oil importer: domestic production has fallen to around 580,000 barrels per day in 2024, against domestic consumption of approximately 1.6 million barrels per day[110]. Domestic refining capacity meets only around 60% of national demand[111]. The resulting import exposure has become a live fiscal priority: the 2026 Iran conflict pushed oil prices above USD 100 per barrel against a government budget assumption of USD 70, with each additional dollar in the oil price adding approximately IDR 6.8 trillion (~USD 380 million) to government spending[112].

Figure 29 | Increased electrification and renewables can materially reduce oil demand.



Source: INDEF & IESR Analysis. Notes: 1. Includes oil (and oil products), including diesel. For transport, where B40/B50 biodiesel is commonly used, B40 diesel was assumed to be used in 2025 and B50 diesel for all years after. For industry, specific biodiesel consumption numbers were incorporated. The volume of bio-fuel has been subtracted from this total to get a "pure" diesel total.
2. Assumes the government's projected oil price of $80 /barrel and a diesel import price of 145 USD/barrel..
Source: INDEF modelling, APBN 2026, Keranga Ekonomi Marko dan Pokok-Pokok Kebijakan Fiskal 2026, S&P Global Platts

110 Indonesia Investments (2024), Crude Oil Indonesia: Production & Consumption.
111 Asia Times (2025), Why oil-rich Indonesia imports most of its fuel.
112 IDN Financials (2026), Oil hits USD 100, Indonesia to keep fuel subsidies through 2026.

By 2035, in the High Electrification scenario Indonesia's oil consumption[113] is reduced by 22% per year versus BAU, equivalent to almost 150 million barrels avoided demand in 2035 alone and around 585 million barrels of cumulative oil demand avoided over 2025-2035 [Figure 29]. Transport is the dominant driver, contributing 140 of the 150 million barrels reduced in 2035, as electric two-wheelers and passenger cars displace petrol- and diesel-fueled vehicles[114]**.** Industry contributes a smaller reduction, with cumulative savings of around 8 million barrels between 2025-2035, from electrification of industrial heat and the replacement of diesel generators with grid-connected and on-site renewable supply. On-grid power generation contributes a small volume, reflecting the limited oil share in on-grid generation today, but its strategic weight is greater than the number suggests. Displacing diesel is one of the largest drivers of the 100 GW renewables build-out, cutting out the most expensive marginal generation on the system. The modelled figure also captures on-grid demand only. Many remote communities still depend on off-grid diesel generators, so the true de-dieselisation potential, and the associated cost and reliability gains, is likely higher than Figure 29 shows.

In total, this translates into around USD 60 billion in cumulative avoided oil import expenditure over 2025-2035, with the highest savings realised in 2035, at USD 15 billion per year. Beyond the headline figure, the savings preserve hard currency reserves, reducing pressure on the Rupiah and lowering Indonesia's exposure to global commodity volatility. To put the scale in context, USD 15 billion per year is broadly equivalent to half of Indonesia's palm oil export value in 2024[115]. At sustained oil prices of USD 100 per barrel, cumulative avoided oil import expenditure rises to around USD 75 billion, a 25% uplift on the central case, and annual subsidy savings rise correspondingly. As global commodity markets remain unsettled following the 2026 Iran conflict, this resilience benefit grows in value over time.

The same reduction in oil consumption that drives import savings also reduces Indonesia's fossil fuel subsidy bill. Because subsidy expenditure is a fiscal flow rather than a direct GDP component, this effect is set out separately in Section 5.3, where savings on oil (products) subsidies result in around USD 16 billion in cumulative savings over 2025-2035 and around USD 3-4 billion per year by 2035, equal to around a third of the 2026 free school meals budget116. Lower oil consumption is therefore the single largest fiscal and economic benefit of the pathway, with effects that flow through both the trade balance (set out here) and the public budget (Section 5.3).

The same reduction in oil consumption that drives import savings also reduces Indonesia's fossil fuel subsidy bill.

113 This chapter groups results for oil and oil products into one datapoint, a breakdown is available in the Technical Appendix. The total oil demand has been adjusted for biodiesel's contribution, assuming B50 is used from 2026 onwards.
114 The uptake of EVs and E2Ws in the high electrification scenario is ambitious and needs policy support. If only half of the uptake is realized, that would mean xx mboe of oil saved per year and $xx savings.
115 GAPKI (2025), Production drops, Indonesian market shrinks
116 Reuters (2026) Indonesia cuts budget of president's free meals programme

5.1.2 Regional electricity exports could generate around USD 8-9 billion per year by 2035

Indonesia is already exploring dedicated renewable generation projects for export to Singapore, paired with subsea interconnection. Under the High Electrification, least-cost scenario , around 46 TWh of low-carbon electricity can be exported to neighboring countries annually by 2035, generating approximately USD 8-9 billion in annual export revenues. This is equivalent to around 4% of Indonesia's total export value in 2025 (around USD 300 billion[117]**).** Beyond the headline revenue figure, electricity exports strengthen Indonesia's export profile in two ways: they rest on multi-decade PPAs, delivering more stable foreign-exchange earnings than commodity exports exposed to global price cycles; and they generate higher-value-added export earnings than Indonesia's current commodity-heavy export mix, anchored on renewable generation and grid infrastructure rather than extracted raw materials.

5.2 Direct GDP impact: additional "future-proofing" investment opportunities and new growth sectors

The High Electrification, least-cost scenario directs around USD 25 billion in additional cumulative "future-proofing" investment into Indonesia's economy over 2025-2035 [Figure 27]. These "future-proofing" investments flow through three channels: the energy system itself, electrification of end-use sectors, and domestic clean energy manufacturing supply chains. A further USD 13 billion in additional investment is mobilised in the two new growth sectors enabled by low-carbon power, regional electricity exports and data centres, both of which depend on access to renewable supply to unlock investment at scale. The economic impact of these investment flows depends on how much value is captured domestically: where equipment, materials, and services are produced in Indonesia, the impact on GDP is larger. This creates a trade-off, since higher local content increases domestic value capture but can raise costs and reduce competitiveness if imposed before competitive domestic capacity exists. The investment consists of the following streams:

1. **Energy system investment.** The High Electrification, least-cost scenario delivers a more efficient use of capital for the energy system than the BAU (2025-2034 RUPTL) supply scenario: it results in USD ~190 billion in cumulative power system investment between 2025 and 2035, a savings of approximately USD 17 billion versus the BAU (2025-2034 RUPTL) supply scenario (USD ~205 billion), while delivering on more electricity demand creating a more efficient system. The efficiency comes from faster scaling of solar PV combined with structural cost interventions, which drive down unit costs over time. In other words, the least-cost supply meets Indonesia's electricity needs at lower total system cost, freeing capital for other parts of the economy.

2. **Expenditure on electrification of end-use sectors.** Electrification of transport, households and industry requires an estimated USD 13 billion in cumulative investment between 2025 and 2035, with two distinct components:

117 BPS Statistics (2026) Exports and Imports of Indonesia in December 2025

- **Transport (USD 7-8 billion)** for the additional deployment of EVs (almost 2 million units), electric two-wheelers (~9 million units), and electrified mining trucks instead of ICE-variants (~11 thousand units) between 2025-2035[118]. While upfront purchasing prices can be higher than the fossil-based alternatives, total cost of ownership for electric two-wheelers (E2Ws) is already lower today because of reduced fuel and O&M costs (see Chapter 1), and early deployments in mining operations are already showing similar cost advantages (see Chapter 1). This investment figure assumes further cost reductions in electric technologies over the next decade; detailed assumptions on these learning rates are set out in the Technical Appendix.

- **Residential (USD 4 billion)** for increased AC adoption (38% of households by 2035) and a (limited) transition to electric cooking (~20 million units).

- **Industry (USD 1.5-2 billion)** for industrial electrification technologies including electric boilers, heat pumps, and electric arc furnaces.

3. **Investment opportunities in strategic domestic clean energy manufacturing.** Building the domestic manufacturing capacity to serve a more electrified, more renewable economy represents a "future-proofing" investment opportunity of approximately USD 30 billion over 2025–2035 in the High Electrification, least-cost scenario. This analysis of the opportunity includes selected strategic elements from the clean energy manufacturing value chain: EVs, electric two-wheelers, electric mining trucks, batteries (for EVs and for the power system) and solar panels.

   - EV manufacturing accounts for the largest share of the green manufacturing investment opportunity between 2025-2035. Domestic manufacturing of electric cars, two-wheelers and heavy-duty vehicles represents approximately USD 10 billion of the manufacturing investment, broadly comparable to the investments into the nickel smelting industry in 2024[119]. Battery manufacturing for EVs and power systems adds a further USD 17 billion, and solar PV manufacturing contributes USD 3 billion. Note: these figures apply existing local content (TKDN) requirements to projected demand – Chapter 6 argues for a more phased local content strategy for solar PV. For more details on local content assumptions and manufacturing investments, see the accompanying technical appendix.

4. **New growth sectors enabled by low-carbon power mobilise around USD 13 billion in cumulative additional investment versus BAU.** Access to competitively priced low-carbon electricity unlocks investment in two new growth sectors that depend on renewable supply: regional electricity exports and data centres. Together they mobilise around USD 13 billion in cumulative additional investment over 2025-2035, with two distinct components:

118 This investment number reflects the incremental costs of purchasing EV equipment versus ICE equipment. For passenger EVs, the price difference is assumed to become negligible from 2030 onwards, and for E2Ws, from 2034 onwards.
119 BKPM (2025), 2024 Investment Realisation Press Conference: nickel smelting received IDR 153.2 trillion of investment realisation in 2024

   - Regional electricity export infrastructure (around USD 9 billion[120]), comprising dedicated renewable generation capacity (large-scale solar and battery storage) for electricity exports to neighbouring markets.

   - Data centre CAPEX (around USD 4 billion) for the approximately 360 MW of additional capacity unlocked by 2035 versus BAU, supported by international hyperscaler operators that require renewable energy as a condition of major commitments (see Chapter 1).

5. The economic impact of these investment streams depends on how much domestic value is captured. A phased approach is likely to maximise economic benefit: rapid deployment can initially rely on competitive imports to reduce costs and accelerate build-out, while domestic manufacturing scales over time as market size, policy support, and investor confidence increase. Specific policy recommendations for balancing solar generation costs while growing domestic manufacturing in Indonesia are set out in Chapter 6.

5.3 Indirect economic impact: fiscal savings, future-proof jobs and structural gains

Beyond the direct GDP impact set out in Sections 5.1 and 5.2, a more electrified economy and more renewable power system deliver a set of indirect gains that reinforce the economic case. These operate through three channels: fiscal space created by lower energy subsidy expenses, future-proof job creation in industries with long-term global growth, and structural and strategic gains that strengthen Indonesia's competitive position over the longer term.

5.3.1 High electrification and least-cost power supply cuts energy subsidies by around USD 20 billion over the next decade, led by lower oil and diesel spending in transport

Energy subsidies are among the largest and most volatile lines in Indonesia's budget. In 2024, the government spent around USD 47 billion on energy subsidies, with roughly 90% directed at fossil fuels[121]. For imported fuels, this bill is highly exposed to global price movements. Reducing fossil fuel demand therefore does more than cut emissions: it lowers a persistent source of fiscal risk.

The high electrification, least-cost supply scenario delivers this reduction. The pathway lowers Indonesia's bill for selected energy subsidies[122] by around USD 20 billion cumulatively over 2025-2035, a 5% reduction against business-as-usual [Figure 30]. Almost all of the saving falls on explicit subsidies paid from the government budget. Implicit price-cap subsidies barely move.

120 The total investment size is ~ USD 45 billion. We assume ~20% domestically manufactured content is used.
121 IISD (2026) Indonesia's Energy Support Measures
122 This section does not aim to provide a comprehensive overview of all existing energy and fuel subsidies in Indonesia today. Instead, it highlights the schemes which would be most impacted by increasing electrification and scaling up renewable power.

Explicit subsidies, funded through the state budget, fall by about USD 20 billion (5%) between the high electrification, least-cost scenario and BAU[123] between 2025-2035. Over the next decade, that is close to one-tenth of a full year of total state spending[124]. Transport is by far the largest component: as electric vehicles displace petrol and diesel, subsidised road-fuel demand drops sharply, cutting oil and diesel subsidies by around USD 16 billion cumulatively. This single lever accounts for roughly four-fifths of the total subsidy savings. Power-generation compensation payments also decline, by about USD 1.3 billion, as the average cost of generation (LCOE) falls in the high-electrification, least-cost supply scenario (C) versus BAU-demand, BAU supply (A). This narrows the gap the government covers between generation cost and the regulated electricity price. Residential LPG subsidies fall by a further USD 1.5 billion as electric cooking displaces subsidised LPG.

Explicit subsidies, funded through the state budget, fall by about USD 20 billion (5%) between the high electrification, least-cost scenario and BAU between 2025-2035. Over the next decade, that is close to one-tenth of a full year of total state spending

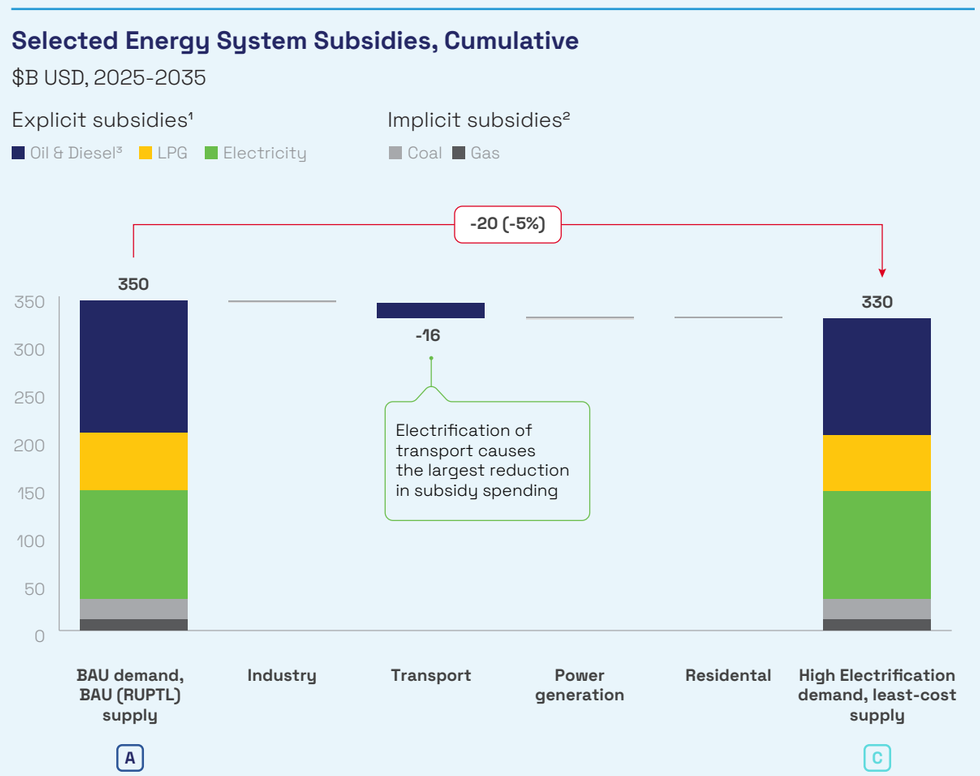
Implicit subsidies[125], the coal and gas price caps that lower prices without drawing on the budget, have a small and slightly offsetting effect.[2] These caps apply mainly to fuel for power generation. Because the high electrification, least-cost pathway satisfies more demand, the implicit coal subsidy rises by around USD 1 billion, partly offset by USD 0.5 billion of lower gas subsidy as gas use in power falls.

123 Explicit subsidies are paid through the government budget: oil and diesel (including the diesel share of biodiesel, assuming B50 blending from 2026), LPG, and electricity compensation payments. Figures are cumulative 2025-2035 and assume current subsidies continue at today's price levels. Price assumptions: crude oil USD 78.6/bbl (ICP) against a USD 70/bbl regulated consumer price; petroleum diesel (import) USD 148.6/bbl and B50 biodiesel USD 138.6/bbl against a subsidised transport consumer price of USD 60.1/bbl; LPG USD 0.93/kg supply against a USD 0.35/kg consumer price; electricity generation cost (BPP) USD 87.6/MWh against a USD 62.2/MWh regulated selling-price cap. Sources: fuel demand (LEAP); power dispatch and LCOE (PLEXOS); oil (ICP, ESDM); diesel and biodiesel (S&P Global Platts, HIP, Pertamina Patra Niaga); LPG (IMF); electricity (PMK No. 73/2025).

124 MUC Consulting (2025) House of Representatives Passes 2026 State Budget Law: Here Are the Structure and Targets

125 Implicit subsidies are price-reducing incentives not on the government budget, such as the domestic market obligation (DMO) price cap on coal and the regulated gas price for power. See Technical Appendix for full methodology. Price assumptions: coal for power USD 77.9/tonne (HBA) against a USD 70/tonne cap and industrial coal USD 116.2/tonne against a USD 90/tonne cap; industrial gas USD 7.1/MMBTU (IMF) against a USD 6/MMBTU cap. Sources: coal (HBA, Ditjen Minerba); gas (IMF); power and industrial demand (LEAP, PLEXOS); caps (Kepmen ESDM No. 56/2022, No. 267/2022, No. 76/2025).

Figure 30 | Savings on selected energy subsidies arise in a more electrified, more renewable energy system.



Note: 1. Explicit subsidies are subsidies paid for through the government budget. Implicit subsidies are price-reducing incentives (e.g., the DMO price cap on coal) that are not on the government's budget. Assumes current subsidies and incentives continue at today's price levels. For full price assumptions, see Technical Appendix. 3. Includes diesel-part of biodiesel, assuming B50 blending from 2026 onwards.

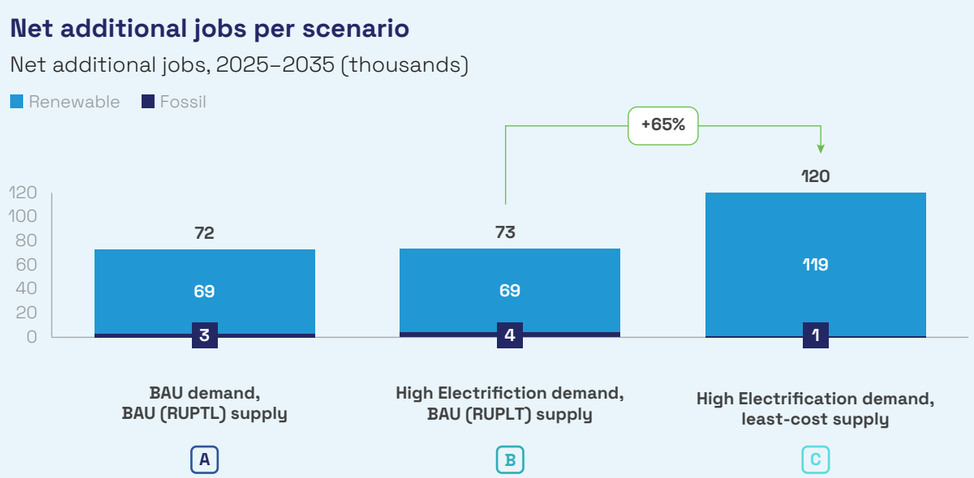
These savings free budget for productive use, with two benefits. First, a smaller subsidy bill reduces exposure to the kind of oil price shocks that forced emergency spending adjustments in 2022 and again in 2026, protecting fiscal stability through commodity cycles. Second, freed budget can be redeployed: directing savings toward infrastructure, education, or industrial support compounds the direct economic gains of the transition, recycling avoided fuel costs into long-term growth.

5.3.2 Power system investments create future-proof jobs

In the high electrification, least-cost scenario, the build-out of a more renewable power system can create around 48,000 (+65%) more jobs than the Business-as-Usual scenario between 2025-2035, and in industries with long-term global growth [Figure 31] In the High Electrification demand, BAU (RUPTL) supply scenario [B], employment changes little as the increased electricity demand is met by running existing fossil power plants more. Power generation jobs

over 2025–2035 can reach approximately 73,000, similar as for the BAU demand, BAU (RUPTL) supply scenario [A]. If the same High Electrification demand is instead met through the least-cost supply, with higher renewable deployment, net employment reaches approximately 120,000 jobs, around 65% more than BAU. The 48,000 incremental jobs come from the choice to invest in new generation capacity rather than rely on existing fossil assets. These figures already absorb a small decline of fewer than 1,000 jobs in fossil-fuel power generation. This decline is small because the least-cost supply scenario does not meaningfully shut down existing fossil capacity, it merely satisfies the new demand through renewables. Additional employment from grid expansion and clean energy manufacturing value chains is not yet included in this analysis and could add further upside (see Section 5.2).

Figure 31 | The High Electrification, least-cost scenario results in the largest jobs increase.



These jobs are future-proof. Renewable generation, electrification, and operation of distributed energy assets sit in industries that are growing globally. Electrotechnical skills are in rising demand across Asia and globally, supporting wage growth, transferability, and worker mobility. Coal-anchored employment faces the opposite trajectory: as global power markets decarbonise, the long-run earnings outlook for coal-sector workers weakens. Investing in the renewable workforce now positions Indonesian workers for the next decades of the energy transition.

Electrotechnical skills are in rising demand across Asia and globally, supporting wage growth, transferability, and worker mobility.

5.3.3 Structural and strategic gains reinforce the case for more electrification and renewables

Beyond fiscal space and jobs, a more electrified economy with a more renewable power supply delivers a set of structural and strategic gains that shape Indonesia's economy through second-order channels: how customers and trading partners reward low-carbon supply, how attractive Indonesia is for foreign investors, the energy system's resilience, and the impact on citizens' health and air quality.

5.3.4 A more renewable supply mix strengthens competitiveness in a greening global economy

Global competitiveness is increasingly shaped by the carbon intensity of production. The EU Carbon Border Adjustment Mechanism (CBAM), which entered into force in January 2026, is the most developed example of this trend, with similar mechanisms now being introduced or considered in other major markets including the UK, Australia, and Canada. The EU CBAM imposes direct carbon costs on imports of steel, aluminium, cement, fertilisers, and hydrogen. Indonesia's total CBAM exposure has been estimated to amount to approximately USD 760 million in export value, equivalent to 5% of Indonesia's exports to the EU in 2023[126]. Iron and steel alone could face over USD 300 million in charges, given their high emission intensity relative to European benchmarks[127].

Carbon pricing is beginning to reshape commodity markets. The London Metal Exchange has outlined plans to facilitate sustainable metal premiums[128], with active discussions underway on low-carbon nickel pricing. As demand for green metals grows, producers are increasingly assessed on the carbon intensity of their electricity supply. For Indonesia, where nickel processing remains heavily coal-powered, this creates a structural competitiveness risk if access to low-carbon electricity does not improve. Nickel is a cornerstone of Indonesia's downstream industrial strategy: a fossil-heavy power mix could translate directly into price discounts or market exclusion for Indonesian nickel in a greening global metals market.

Corporate investment decisions reinforce this pressure. Multinational manufacturers, especially consumer-facing brands, increasingly require low-carbon electricity as a condition for investment [Figure 33]. In 2024, Tesla declined to invest in Indonesian manufacturing, citing the coal-heavy generation mix as inconsistent with its sustainability strategy[129]. H&M has committed to sourcing 100% renewable electricity across garment production by 2030 and phasing out coal boilers from its entire supply chain by end-2026[130]. Across metals, chemicals, manufacturing, and data centres, a fossil-heavy power mix raises the risk of supply chain exclusion, reduced FDI, and commodity discounts.

126 IESR (2024) Indonesia Energy Transition Outlook
127 Trade Expo Indonesia (2024) CBAM Dan Implikasinya
128 Fastmarkets (2025) LME outlines plan for 'sustainable' base metal premiums: LME Week 2025.
129 Kumparan (2024) Terungkap, Ini Alasan Tesla Ogah Investasi di Indonesia.
130 H&M Group (2025) Annual and Sustainability Report 2024.

Figure 33 | A lack of renewables and over-reliance on coal is already hurting Indonesia's global competitiveness.

Companies	Example	Impact
adaro MINERALS / HYUNDAI	MoU in place between Adaro and Hyundai for aluminium, but **Hyundai withdrew** from the deal after **rising public pressure to reduce reliance on coal-fired suppliers**	**Loss of 50-100 kton of Aluminum sales** to Hyundai per year for Adaro minerals due to reliance on coal power
SAMSUNG	Wanted to increase renewable energy use for phone production but **could not get access to renewables**	**Shifted majority of production to Vietnam,** which does **allow for power wheeling** and has grown renewables significantly
amazon	Wanted **100% renewable energy for data center** operations and signed a 210 MW Solar PV GEAS with PLN in 2022, but delivery has been significantly delayed	**Increased risk of future data centers choosing other regions** where it is easier to secure renewable power (e.g., Malaysia)
TESLA	Has been in discussions with Indonesian Gvmt to invest in manufacturing, but **declined because of fossil-heavy electricity system** not being aligned with sustainable EV manufacturing	**Reduced investment** into and growth of manufacturing industry in Indonesia
tmai	Indonesia has ~25 solar panel manufacturers with 6-11 GW/year of production capacity. With **too little domestic demand to absorb output** and tariffs on exports to the US, producers (including TMAI) warn of furloughs and layoffs	**Underused factories and job losses** in a young solar-manufacturing sector, leaving Indonesia unable to build a competitive domestic clean-energy supply chain.

Notes: GEAS = Green-Energy-as-a-Service
Source: PROSPERA/BINS Research, BNEF (2025), Suruhanjaya Tenaga. Systemiq Analysis, Kumparan (2024), Bloomberg Technoz (2026)

5.3.5 Renewables and electrification improve energy cost predictability for industry

For energy-intensive and trade-exposed sectors, cost predictability is critical. In Indonesia's current system, industries remain indirectly exposed to global fossil fuel markets through tariff regulation and coal supply rules.

Grid-connected firms (e.g., light manufacturing facilities) depend on regulated electricity tariffs. While tariffs may be stable in the short term, they are subject to adjustments linked to fuel prices, exchange rates, and inflation. For example, in July 2022 the government adjusted tariffs for certain non-subsidized household and government customers, raising rates by about 18%[131].

131 Antara News (2022) Hiking electricity rates triggers 0.019-percent inflation: official.

Although tariffs were held flat in several quarters of 2024–2025 despite rising input costs, this stability was maintained through increased compensation payments to PLN. In other words, tariff risk was deferred rather than removed. For energy-intensive sectors, the possibility of future tariff increases remains a material concern.

Captive coal users face a similar exposure: industrial sites, such as nickel processors, currently rely on coal supplied under the Domestic Market Obligation (DMO) at capped prices. Nickel industry stakeholders expressed their concerns over the availability of DMO coal supply under the current rapid growth in the nickel sector. As nickel smelting capacity expands and DMO supply tightens, smelters could face partial exposure to international coal prices, which would raise coal input costs by up to 40% and nickel production costs by up to 15%[132].

For both grid-connected and captive power users today, cost stability ultimately depends on regulatory mechanisms that buffer fossil fuel price volatility. Industrial energy costs are therefore shaped not only by market fundamentals, but by policy decisions on tariffs, subsidies, coal allocation, and production quotas. Increasing the share of renewables in the power mix reduces this structural dependence. Renewable generation does not rely on ongoing fuel inputs and is not directly exposed to global commodity markets.

For individual sites, electrification combined with on-site solar and storage is also a risk management strategy. By shifting from fossil fuel combustion to electric processes and investing in captive renewable generation, firms can reduce exposure to tariff uncertainty, fuel supply constraints, and regulatory shifts.

As one industrial stakeholder noted, industrial sites see electrification and on-site renewables as a critical risk reduction measure, because they cannot foresee or control how PLN tariffs and energy regulations may change in the future.

132 The Domestic Market Obligation (DMO) ringfences 25% of national coal production for domestic use at a capped price. Following the recent reduction in the annual coal production quota from 800 Mt to 600 Mt, total DMO supply falls from approximately 200 Mt to 150 Mt per year. Nickel coal demand is meanwhile approaching 100 Mt per year, around two-thirds of available DMO supply. In the event of a DMO shortfall, nickel producers would need to procure coal at international market prices. Cost impact assumes an export coal price of USD 130/t (ICI 1, February 2026)

CASE STUDY | Electrification and rooftop solar in practice at Haleon Indonesia

Haleon, the consumer healthcare manufacturer, has paired electrification of heat with rooftop solar at its Pulogadung site in East Jakarta, illustrating both the pace at which firms can deploy these technologies and the practical conditions that shape implementation.

Haleon installed a rooftop solar system of around 417 kWp in 69 days, and it now meets roughly 20-25% of site electricity demand. Permitting took longer than construction: the connection was secured around six months later than initially planned, reflecting the bi-annual application windows and quota allocation issues process described in Box C. The current system covers half of the available rooftop space and could have been larger, but under the existing rules Haleon would not be compensated for exporting additional power to the grid.

On the demand side, the site moved from oil-based heat to electric steam generation and electric water heating. The switch reduced operating costs and lowered the site's direct exposure to oil price movements on the thermal side of the operation.

Together, electrification and on-site solar also support a broader risk-management objective. While external electricity tariffs and fuel prices are outside the company's control, on-site generation and electrified processes give the site more direct control over a portion of its energy costs. The team also highlighted a wider motivation: demonstrating that practical decarbonisation steps are feasible in Indonesian manufacturing and can encourage similar action across the sector.

5.3.6 A more diversified energy system is more resilient to (fuel) supply shocks and geopolitical disruption

This increased resilience comes from two sources: a more diversified power mix on the supply side, and reduced oil dependence across the economy on the demand side.

On the supply side, heavy reliance on coal creates operational concentration risk. In January 2022, the government imposed an emergency coal export ban after domestic supply shortfalls left 20 PLN coal plants critically low on fuel[133]. The episode illustrated that a coal-dominated system remains vulnerable to supply-chain bottlenecks even in a major coal-producing country. Renewable assets require no ongoing fuel inputs once built, are geographically distributed and are modular in scale, reducing the likelihood that a single disruption affects large parts of the system.

133 Ministry of Energy and Mineral Resources of Indonesia (2022) Preventing Power Outages, Gov't Temporarily Bans Coal Export.

On the demand side, electrification reduces Indonesia's exposure to oil price shocks. Transport is the dominant consumer of oil products in Indonesia (73% of 2023 consumption), but industry (9%) and residential (15%) sectors also depend on oil[134]. A geopolitical shock that moves the oil price ripples across the trade balance, the subsidy bill, cost of living and industrial production costs simultaneously, as the 2026 price spike following escalation in the Iran conflict made concrete. As Chapter 1 showed, the cost of industrial heat delivered via oil boilers more than doubled in 2026. Electrification reduces this exposure by shifting transport and industrial energy demand onto the power grid, where the fuel mix is more diverse and increasingly domestic. For example, Figure 29 already illustrated that by 2035, 140 million barrels of oil could be saved per year through electrification of transport.

5.3.7 Cleaner air, better health, and stronger climate credibility

Air pollution imposes large costs on Indonesia's economy and population. The World Bank estimated the total economic burden of air pollution at approximately USD 220 billion in 2019[135]. In Jakarta, annual average PM2.5 concentrations reached six times the WHO guideline in 2023. IESR attributes around 10,500 premature deaths and USD 7.4 billion in annual health costs to coal-fired power plants alone[136]. Accelerating the coal phase-out to 2040 could avoid a cumulative 182,000 premature deaths and approximately USD 130 billion in associated health costs[137]. A more renewable, electrified system reduces health impact and costs through two reinforcing channels: lower supply-side emissions from power generation and lower demand-side emissions through the replacement of coal boilers, diesel generators, and combustion engines with electric alternatives. The last group can have an outsized impact, as s combustion sources are often embedded in urban areas where human pollution exposure is highest.

Renewable deployment also strengthens Indonesia's climate credibility. Indonesia has committed to reducing emissions by 32% below Business-as-Usual by 2030, rising to 43% with international support, and to net zero by 2060[138]. Credible progress in the power sector strengthens Indonesia's standing as a G20 economy and major energy producer, broadening access to concessional finance, climate partnerships, and international capital for industrial transformation.

134 International Energy Agency (n.d.) Indonesia – Oil, Countries & Regions.
135 World Bank (2022) The Global Health Cost of PM2.5 Air Pollution: A Case for Action Beyond 2021.
136 CREA and IESR (2023) Health Benefits of Just Energy Transition and Coal Phase-out in Indonesia.
137 CREA and IESR (2023) Health Benefits of Just Energy Transition and Coal Phase-out in Indonesia.
138 Republic of Indonesia (2025) Second Nationally Determined Contribution, submitted to UNFCCC.



Chapter 6

Capturing Indonesia's solar and electrification opportunity: a roadmap for action

Capturing the economic gains set out in Chapter 5 depends on coordinated action across both supply and demand. One set of actions cuts across every intervention that follows: the rebalancing of support between fossil fuels and renewables. Indonesia currently directs around USD 47 billion a year to energy subsidies, of which 90% for fossil fuels139. These support mechanisms create an artificial cost advantage for fossil fuels, that undermines the competitiveness of both renewables and electrified end uses. Crucial recommendations to re-balance these supply-side incentives that favour fossil fuels today are well established and have been the topic of many studies[140 141 142 143 144 145]. Key elements include phasing down fossil fuel price supports such as the Domestic Market Obligation and HGBT gas pricing, including captive coal in the Emissions Trading System[146], and redirecting freed fiscal space toward renewable generation and storage, grid investment, and electrification. This is not a one-off reform but a progressive rebalancing that should scale as renewables and electrification reach tipping points: acting too slowly prolongs fossil lock-in, while acting too abruptly creates political and fiscal risk Because this topic is already covered in-depth by other studies, this report does not cover these recommendations again.

Building on this foundation, this report concentrates its recommendations on the two areas where it can add the most: bringing down the cost of solar generation and accelerating electrification of demand. On the supply side, solar costs need to come down materially through targeted interventions, bringing them in line with the levels leading solar markets already achieve. Four categories of intervention enable this: i) fast-tracking catalytic grid-scale projects that anchor early demand and generate bankable precedent, ii) removing barriers to rooftop solar, iii) policy support on key cost components to address the structural drivers of Indonesia's solar cost gap, and iv), a phased local content strategy that builds Indonesian manufacturing capacity while keeping deployment costs competitive. These supply-side interventions need to be paired with stable, **long-term demand-side electrification policies in transport and industry.**

The chapter is structured in two sections. Section 6.1 sets out how to scale solar at lower cost through the four categories of intervention. Section 6.2 sets out how to accelerate electrification of demand, particularly in transport and industry.

6.1
Scaling solar at lower cost: four categories of intervention

Closing Indonesia's solar generation cost gap with leading markets requires action across four categories of intervention [Figure 34]. The diagnosis is set out in Chapter 3: the gap is largely driven by elevated module and balance-of-system costs (linked to local content requirements),

139 IISD (2026) Indonesia's Energy Support Measures
140 IEA (2022) An Energy Sector Roadmap to Net Zero Emissions in Indonesia
141 Ember (205) Response to Indonesia's Just Energy Transition Partnership (JETP) Progress Report 2025
142 IISD (2026) Indonesia's Energy Support Measures
143 World Bank (2026) Indonesia Economic Prospects, June 2026
144 World Bank (2024) Indonesia's Fuel Subsidies Reforms
145 IESR (2025) Indonesia Energy Transition Outlook 2026
146 Ember (205) Response to Indonesia's Just Energy Transition Partnership (JETP) Progress Report 2025

high land acquisition costs (driven by regulatory complexity and the absence of pre-zoned land), and high grid connection costs (driven by long distances to the transmission network), with permitting and financing adding further cost pressure and project-level risk.

The cost drivers identified above are addressable, although bringing them down will not happen automatically. It requires focused and organized action across four categories of intervention:

Category 1

Fast-track catalytic grid-scale projects that anchor early demand and generate bankable precedent, including premium-buyer projects (e.g., data centers and power exports) and the first phase the 100 GW programme (the "quick-wins" phase of the programme mentioned in section 2.5, including de-dieselisation projects). These near-term projects build deployment scale, reduce financing costs through bankable precedent, and unlock follow-on private capital.

Category 2

Remove barriers to rooftop solar by reforming the quota system that currently constrains distributed rooftop deployment. Faster rooftop uptake scales capacity quickly and adds to domestic module demand, helping bring down module and balance-of-system costs for utility-scale projects too.

Category 3

Policy support on key cost components, particularly to reduce land and grid connection costs. A centralised land mechanism, pre-zoned renewable development areas, and accelerated transmission expansion address the structural drivers of Indonesia's cost premium. These interventions benefit not only solar deployment, but also other renewable generation technologies that face the same land and grid constraints.

Category 4

A phased local content strategy, that brings module and balance-of-system costs towards import parity in the near term while progressively building Indonesian manufacturing capacity up the value chain.

While these interventions focus on the 2025-2035 period that the modelling covers, the solar cost-reduction trajectory does not end there: global solar costs have followed a steep learning curve over the past decade and are projected to continue falling, meaning Indonesia's solar generation costs are likely to reduce further beyond 2035.

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Figure 34 | Bringing down Indonesia's cost of solar generation

Breakdown of Indonesia's versus India's solar LCOE today

$c/kWh, grid-scale, favourable solar locations



Notes: 1. Survey results of 12 to 20 c/Wp, with upper range representing local manufactured prices, lower range represents import price, ex. Logistics.; 2. BoS includes inverter, electrical components, mounting or floaters (if applicable) and others. 3. Includes EPC services and civil works. Upper end of range represents remote area. 4. Based on average land price and additional land conversion cost for 5 major islands modelled in our study (Java, Sumatera, Kalimantan, Sulawesi, MPNT). High end of the range corresponds with Java, low end with Kalimantan. 5. Large range as cost depends on connection type (subsea/overland etc.) and distance to transmission grid, assumes only transmission lines, no new substation built.
Source: Expert input

4 categories of interventions to bring down the cost of solar in Indonesia

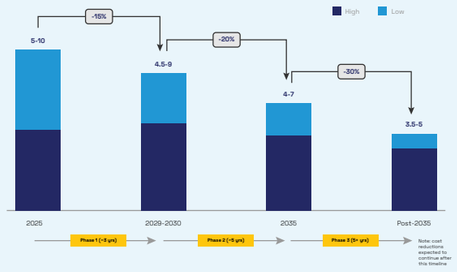
Impact on LCOE component

	Objective	Interventions	Timeline for impact on LCOE (If implementation begins today)
Fast-track catalytic projects	Unlock catalytic projects through two time-bound tracks: **premium buyer projects (Singapore exports, data centres) and the first part of the 100 GW programme** (inc. de-dieselisation)	• Allow for long-term export permits • Set up regular (e.g., annual) RES auction rounds, with clear bidding and contracting frameworks • Develop standard implementation for innovative RE procurement (e.g. PPA) • Relax local content requirements for catalytic projects	**Short term (<2030)**
Remove barriers to rooftop solar	**Unlock scaling of rooftop solar** across Indonesia	• Reform solar quota system to enable easier deployment of larger volumes of rooftop solar and enable economies of scale	**Short term (<2030)**
Policy support on key cost components	**Remove the structural cost and regulatory roadblocks** that drive Indonesia's cost gap with leading markets	• Improve land acquisition process and sup-port on land costs for utility-scale projects • Build out grid and improve access for utility-scale projects	**Medium term (<2035)**
Phased local content strategy	**Build Indonesian solar manufacturing progressively up the value chain** without holding up near-term deployment and increasing component costs	• Design & implement revised phased local content strategy for solar PV and other RES • Scale-up domestic manufacturing capacity and capability	**Longer term (>2035)**

Indicative outcomes of the interventions on Indonesia's solar LCOE

$c/kWh, grid-scale, average high-low across five modelled regions

- Balancing of local content requirements for less strategic components brings down component costs
- Scale and learning through catalytic projects (e.g., on RES procurement processes) brings down development, permitting and financing costs
- Standardized and streamlined land acquisition and grid connection brings down costs
- Solar PV deployment scales (inc. RUPTL, 100 GW delivery and rooftop) supporting cost reductions across components, EPC and financing
- Coordinated scale-up of domestic solar manufacturing, bringing domestic production costs in line with import prices
- Continued policy support brings key cost components further down (land, grid connection)
- Scale drives down EPC, financing and dev. & permitting costs



6.1.1 Category 1: Fast-track catalytic projects

Fast-tracking a catalytic wave of solar projects can create the demand pull and market precedent on which subsequent cost reductions depend. Two tracks of catalytic projects are identified:

- **Track 1: Premium buyer projects.** Buyers willing to pay a premium and contract directly with IPPs, at a higher rate than PLNs current tariffs. The two most promising near-term routes are renewable electricity exports to Singapore and power supply for data centre developers that have renewable energy commitments.

- **Track 2: Supporting the first phase of the 100 GW programme,** planned for delivery in 2026 as the "quick-wins" phase of the broader programme (see Section 2.5). This first wave combines rooftop solar deployment, dedieselisation projects (where the economics of replacing diesel generators with solar plus storage are already favourable), and utility-scale solar projects.

Four interventions deliver this category, each targeting a specific driver of solar cost or project risk. Their effect on the solar LCOE is summarised in Figure 33.

- First, **unlocking electricity exports**, for example through long-term export permits for the planned Singapore export projects. This project is now moving forward, and that momentum needs to be maintained. Scaling exports in line with the 100 GW programme would open the possibility for renewable energy deployment more broadly, with export demand acting as a premium buyer for Track 1.

- Second, **developing standard implementation frameworks for innovative renewable procurement**, such as standardised PPAs and power wheeling arrangements, lowers financing costs by establishing bankable precedent and reducing development risk for early projects.

- Third, **Indonesia should move from one-off, single-project procurement to a regular, predictable renewable capacity auction calendar.** PLN's Giga One scheme[147] is a step in the right direction: it bundles multiple projects into a single procurement round, giving the market a larger and clearer volume signal than project-by-project tendering. The task now is to make this cadence regular and predictable, through an annual auction calendar with pre-announced volumes that ramp in line with the 100 GW programme and the cost-reduction trajectory. Predictability lowers costs on three fronts: financing costs fall as lower development risk is priced in, supplier and EPC capacity scales against the certainty of future demand, and competition drives tariffs down across successive rounds. Two design features enable these gains: clear, bankable bidding and contracting frameworks, and binding post-award milestones from financial close to commercial operation that prevent the stalls that sometimes follow tender wins in Indonesia. Storage should be procured through the same calendar as a distinct auction product, via regular, dedicated solar-plus-storage rounds rather than case-by-case add-ons; Box J sets out why storage is critical to the build-out and the steps needed to scale it.

- Fourth, **balancing initial local content requirements for catalytic projects** brings module and balance-of-system costs toward import parity in the near term. Allowing imports of less strategic components while using segments of the 100 GW programme as an anchor for domestic manufacturing gives the domestic supply chain a targeted demand signal without loading early projects with above-market hardware costs.

Together, these interventions should deliver visible cost reductions before 2030: lower module and BoS costs as catalytic projects access components at import parity, lower permitting and development costs as export projects are unblocked, and lower financing costs as bankable precedent reduces project risk.

6.1.2 Category 2: Remove barriers to rooftop solar

Category 1 addressed utility-scale catalytic projects. Rooftop solar is a distinct deployment channel, which is still barely used in Indonesia. As set out in Chapter 2, Indonesia's rooftop solar deployment remains very low at around 775 MW in 2025[148], far behind regional peers such Vietnam, where over 9.5 GW of rooftop solar has been deployed[149]. The constraint is not rooftop space or resource: it is the current rooftop permit quota system, as introduced in Box C.

Three features of the current framework, set under MEMR Regulation No. 2/2024, hold deployment back. First, the cumulative 2024-2028 quota of 5.7 GW is very low, and only a small fraction of the 100 GW solar programme. Second, net metering was abolished under the same regulation, so customers can no longer offset exports against their electricity bills, weakening the economics of residential rooftop solar. Third, the bi-annual application windows can delay projects by up to six months when allocations are missed or a system's quota is already filled.

Two policy options can unlock Indonesia's rooftop solar opportunity. The first is to **significantly improve the existing framework**: raise annual quotas in line with the 100 GW ambition and demand (in 2026, demand for quotas exceeded supply by 40%[150]) , restore a form of net metering or compensation for exports[151], publish sub-system quota allocations transparently so developers can target locations with available capacity[152], and replace the bi-annual application windows with rolling applications. The second, more ambitious option is to **abolish the quota system entirely for systems below a**

Two policy options can unlock Indonesia's rooftop solar opportunity.

147 PLN has already begun moving in this direction. In 2026, it launched GIGA ONE, a new integrated procurement model that bundles multiple solar sites, 22 locations totalling 1.2 GW under the first tranche (Mentari Nusantara I), into a single consolidated tender rather than tendering each project separately. Bundling is designed to make projects more bankable and financeable as a package, and to streamline procurement through to construction. A second tranche, Mentari Nusantara II (1.1 GW), is planned for launch in the second half of 2026.

148 PLN presentation, Dec 2025
149 Earth Journalism Network (2026), A Reporting Tipsheet on Renewable Energy in Vietnam
150 Bloomberg Technoz (2026) Kuota PLTS Atap 2026 Sudah Habis, Bakal Ditambah 500 MW Lagi
151 AESI / IESR (2023), joint position statement on the proposed revision of MEMR Regulation 26/2021; IESR (2024), MEMR Regulation No. 2/2024 Limits Public Participation to Support Energy Transition through Rooftop Solar PV.
152 IESR (2024), Efforts to Encourage the Effectiveness of Rooftop Solar Quota Fulfillment

defined size threshold (for example, residential and small C&I installations) and installations that are combined with batteries, allowing self-consumption-driven deployment without prior PLN approval. Grid-impact assessments would be retained only for larger installations where they have engineering value. In both cases, robust grid and storage planning is essential to ensure rising rooftop generation does not destabilise the system, for example through reverse-flow voltage spikes, particularly for net-metered installations.

Removing these barriers to rooftop solar, paired with grid and storage planning from the outset, delivers two benefits. First, rooftop capacity can scale quickly, since installations are small, modular, and sited on existing buildings, avoiding the land acquisition and grid connection challenges that slow utility-scale projects. Second, rooftop solar adds to total domestic solar demand, which helps module and balance-of-system costs move down the learning curve. Because these hardware costs are shared across rooftop and utility-scale projects, faster rooftop deployment strengthens the demand anchor for the domestic manufacturing build-out set out in Category 4 and supports the cost-reduction trajectory outlined in Chapter 3.

6.1.3 Category 3: Policy support on key cost components

Removing the structural cost and regulatory roadblocks that drive the largest portion of Indonesia's solar generation cost gap with leading markets is critical to meeting the RUPTL renewable targets and the 100 GW programme. As demonstrated in Chapter 3, two components carry the largest addressable cost premium: land acquisition and grid connection. Interventions to bring down both cost components are listed in the sections below. These interventions also benefit other renewable generation technologies, including geothermal and hydropower, which face many of the same structural constraints, and should deliver visible cost reductions in the medium term, before 2035.

These interventions should not be seen as standalone fixes but as consecutive stages of the same project-development chain, which ends in the procurement / tendering step set out in Category 1: pre-cleared, standardised land and grid access delivered to the edge of the site are what let projects be tendered at low cost and reach financial close quickly.

Land costs

Land acquisition and conversion is one of the highest-impact areas for policy intervention on solar generation costs in Indonesia, both because of its large direct contribution to project cost and because of its role in determining whether projects reach financial close at all.

Indonesia should anchor its land-access strategy for renewables on land-use planning and designation, combined with permitting acceleration and financing/de-risking support. India's experience shows the scale of potential impact: state governments used the Land Revenue Code authority to designate so-called wasteland, technically state-owned but empty, as renewable energy development sites, bypassing both private purchase and forest release requirements.

Figure 35 | Intervention options to reduce land costs for renewables projects in Indonesia.

Four Intervention Options to Lower Land Costs for Renewables in Indonesia

Intervention Option	Key Mechanism	Design Features	State Cost	Time to Impact
Direct state-led land bank The government brings down costs of land acquisition and conversion by securing land and leasing it to renewables developers	A dedicated state agency acts as and bank: it acquires land at scale, holds the title, and leases serviced plots to IPPs through long-term tenure, with price control over lease fees.	Single agency holds land, financing and tendering authority; land is bought before renewables tendering, often with concessional finance; developers bid for plug-and-play sites with no land risk.	**High** Direct acquisition + holding	**High** Substantial regulatory reform
State-aggregated re-designation zoning Government identifies priority areas and designates them for RES development, such as the newly introduced (Pre-Approved) Renewable Energy Zones.	Provincial or state government identifies pre-existing public, degraded or non-agricultural land, performs zoning and clearance work, and transfers serviced parcels to a RES developer. This should be complemented with price-control over land prices or lease fees.	Land is typically already state-owned or low-conflict (wasteland, salt pans, ex-mining). Central government support for Detailed Project Report preparation and grid infrastructure. The implementing agency aggregates land and auctions it to private developers at at sub-market prices.	**Med-High** Zoning, clearance & DPR support	**Med-Long** Some regulatory reform
Developer-led acquisition with state de-risking Government identifies priority areas and designates them for RES development, such as the newly introduced (Pre-Approved) Renewable Energy Zones.	Provincial or state government identifies pre-existing public, degraded or non-agricultural land, performs zoning and clearance work, and transfers serviced parcels to a RES developer. This should be complemented with price-control over land prices or lease fees.	Land is typically already state-owned or low-conflict (wasteland, salt pans, ex-mining). Central government support for Detailed Project Report preparation and grid infrastructure. The implementing agency aggregates land and auctions it to private developers at at sub-market prices.	**Med** Concessional finance & offsets	**Medium** Setting up instruments
Permitting acceleration Government provides permitting support when land requires zoning release (e.g., forestry or agricultural land) and speed up operational permitting procedures.	Government designates priority renewable zones with fast-tracked permitting and master-planning, combined with simplifying and streamlining operational permits such as Environmental Impact Assessments (AMDAL) for Solar PV projects. This reduces the duration of project development cycle, as solar PV should not need the same extensive impact assessments as coal-fired power plants.	Strategic zones mapped in national power plans; projects within zones receive priority pricing, fast-tracked environmental approvals and grid-access guarantees. No additional fiscal expenditure on land, developers handle land acquisition.	**Low** Zoning, clearance & DPR support	**Med-Long** Some regulatory reform

Overall, during stakeholder conversations, we have identified four intervention options that are relevant to Indonesia's land-related issues. These range from heavy state involvement to lighter regulatory facilitation, and they can be combined [Figure 35]. Delivery of these options is not straightforward: implementation risks in the Indonesian context include social acceptance around land use, institutional capacity to aggregate land at scale, and contestation over allocation.

BOX I | Unlocking new land for solar: AgriPV and former mine sites could ease Indonesia's land constraint_

AgriPV and mine-site repurposing are two promising options to unlock new land areas for Solar PV, without competing for scarce greenfield land. AgriPV, the co-location of solar panels with agricultural production, could meaningfully expand the land available for solar in Indonesia without competing with food production, though the scale of the opportunity still needs validation. ETC's 2026 Unlocking Solar at Scale report finds that around 30% of India's cropland, 47.5 million hectares, is technically suitable for AgriPV, with a high-potential scenario suggesting this land alone could generate more than twice India's projected 2050 electricity demand[153]. Indonesia may hold significant potential of its own, given that agricultural land accounted for 29% of its total land area in 2023[154]. To assess the size of this opportunity, a dedicated assessment of AgriPV crop suitability under Indonesia's climatic and terrain conditions must be undertaken, particularly because of its more mountainous landscape, which differs from the largely flat cropland assessed in the India study.

Repurposing mining sites is another viable route to free up land for solar: studies have shown that retiring Indonesian coal mines could support up to 60 GW of solar capacity. Indonesia has over 100,000 hectares of coal-mining land with potential for conversion to solar PV[155]. This conversion is already underway: China currently leads the way with 90 operational coal mine-to-solar conversions, having delivered 14 GW with 9 GW still in planning. In Indonesia, 430 MW is currently in the pipeline, with development still in the early stages through cooperation between Pertamina New & Renewable Energy and PT Bukit Asam across Ombilin, Tanjung Enim, and Bantuas[156,157]. Former mine sites can offer several advantages over greenfield locations, including clearer land ownership, proximity to substations and other power infrastructure, and, in some cases, existing grid connections or electricity-supply arrangements (power export licenses), although difficult terrain and rehabilitation requirements may increase development costs.

Repurposing former mines and expanding AgriPV could help ease land constraints on solar development in Indonesia, but both approaches would require new regulatory frameworks and ways of working. For AgriPV, that involves dual-use land classification, crop-specific standards and pilot programmes that safeguard agricultural production. They should also enable farmers to benefit from lower energy costs or electricity sales supported by reliable power-purchase agreements and adequate local grid capacity. For former mining sites, renewable repurposing should be incorporated into mine-closure and rehabilitation plans, with clear post-mining land ownership, streamlined permitting, and early coordination on grid access.

153 ETC (2026) Unlocking Solar at Scale
154 World Bank (2023) Agricultural land (% of land area) - Indonesia
155 World Bank (2026) Spatial Analysis of Coal Mining Lands for Renewable Energy Repurposing in Southeast Asia
156 PT Bukit Asam (2026) PTBA dan PNRE Jajaki Pengembangan PLTS di Lahan Pascatambang
157 Global Energy Monitor (2025) Bright side of the mine

Grid connection and transmission costs

Grid connection and transmission costs are a major driver of the delivered cost of renewable electricity, and can be lowered through two channels. First, developers currently bear the cost of connecting their projects to the transmission grid, and that cost rises with distance; as the grid expands closer to generation sites, connection distances and developer costs fall. Second, the regulated tariff for using the grid can be reduced, lowering the wheeling cost embedded in the delivered price. Both depend on transmission build-out, which is costly and complex given Indonesia's distances and geography. International experience shows how this can be done (Appendix I), and points to the intervention options set out below for Indonesia.

Figure 36 | Intervention options to reduce transmission costs for renewables projects in Indonesia.

Two Design Choices And Interventions To Lower The Costs Of Using The Grid In Indonesia

Intervention Option	Key Mechanism	Design Features	Cost Borne By
Full cost socialisation "All ratepayers Pay"; all costs for building/upgrading transmission lines are charged across the full consumer base	Transmission infrastructure for renewables is built by the state or regulated utility, and the entire cost is recovered through a uniform tariff levied across all grid users, similar to PLN's existing Biaya Pokok Produksi (BPP, or Cost of Generation).	Regulator authorises the build before generation is committed, breaking the chicken-and-egg dynamic. Transmission costs are spread over millions of consumers, making per-customer impact small; generators face zero transmission capex, improving project IRRs.	**ALL RATEPAYERS** Uniform tariff on every grid user via PLN, as with the current BPP mechanism.
Transmission acceleration fund Transmission projects are accelerated via a state-led fund/facility, involving low-rate financing/instruments from development finance institutions or government bonds.	A (state-owned) green bank or Development Finance Institution (DFI) provides concessional debt to transmission builders (state-owned or private), lowering the financing-cost component of the line and the regulated tariff that recovers it.	Concessional finance is provided at sub-commercial rates and longer tenors than markets offer, often paired with grants for early works. The transmission asset remains regulated and revenue-determined; subsidy is purely on the cost of capital. Mechanism can be paired with competitive procurement of the transmission build.	**STATE / DFIS** Concessional public finance subsidises the cost of capital, not the asset
Deep-vs-shallow connection split Transmission lines are split between deep (transmission backbone or interconnection) and shallow (connecting backbone to nearest step-down transformers). Both have different investors and entities in charge of the end-to-end building out process.	A pre-defined and regulated boundary divides transmission costs: defined entities (e.g., developers, PLN) fund only the line and substation upgrades from their generation site to the nearest existing grid node ("shallow" connections), while another entity (e.g., INA or Danantara) funds all reinforcement of the backbone ("deep" connections).	A pre-defined and regulated boundary divides transmission costs: defined entities (e.g., developers, PLN) fund only the line and substation upgrades from their generation site to the nearest existing grid node ("shallow" connections), while another entity (e.g., INA or Danantara) funds all reinforcement of the backbone ("deep" connections).	**SHARED** Danantara funds backbone (deep); developers and PLN fund site-to-node lines (shallow).

International experience shows land and transmission interventions to scale renewables are well precedented. Across markets, the pattern is consistent: where a single empowered entity aggregated land, coordinated transmission, and structured procurement, deployment accelerated and tariffs fell sharply. India's solar park scheme reached record-low tariffs by bundling pre-cleared land with shared transmission at the edge of designated parks, so that land and grid constraints were resolved before projects were tendered. South Africa's REIPPPP mobilised over USD 17 billion in private investment on the same principle of coordinated state facilitation. Appendix I sets out case studies from India, Australia, South Africa, Vietnam, and Morocco.

For Indonesia, several intervention models can bring down transmission costs, each allocating the cost differently between developers, the state, and ratepayers

For Indonesia, several intervention models can bring down transmission costs, each allocating the cost differently between developers, the state, and ratepayers [Figure 36]. Based on the interventions that have been implemented globally to structure the costs of transmission investment, a deep-vs-shallow investment split between Danantara (the newly formed sovereign wealth fund) and PLN could pave the way for a breakthrough that switches from the current PLN-led model of transmission investment to share the burden with Danantara. By combining this with the lease-back model (Danantara leasing back to PLN for operational control of assets), this approach will keep PLN's sovereignty over the grid system but reducing the burden of PLN in investing/building out the grid.

The interventions proposed by this report should be seen as one delivery chain: pre-development site identification, land pre-clearing and standardisation and grid access (this section), feeding into the regular auction calendar (Category 1). Indonesia's renewable energy processes are currently spread across MEMR, KLH, ATR/BPN, PLN, and BKPM, with no entity holding integrated authority. A state-owned entity such as a BUMN designated on real estate or land-banking can play this role for the Indonesia power sector, or Danantara regarding several key transmission deployment sections (e.g., backbone, inter-island connectors).

Scaling storage can also reduce the transmission investment needed in the first place.

Scaling storage can also reduce the transmission investment needed in the first place. By shifting solar output away from congested periods, batteries relieve transmission and distribution constraints and improve utilisation of existing lines, deferring or avoiding some reinforcement while maintaining reliability. Storage is therefore a complement to the transmission interventions above, not a substitute: it can lower near-term investment at specific congestion points, but reducing wheeling costs still depends on the transmission-financing models set out here. Box J sets out why storage is critical to Indonesia's build-out and the steps needed to scale it.

BOX J | Unlocking utility-scale storage as a system asset

Storage is integral to the renewable build-out this report models. In the least-cost supply scenario, the modelling adds around 17 GW of storage capacity (of which 13 GW BESS, 3 GW PHS) by 2035 alongside 65 GW of solar PV, shifting daytime solar into the evening peak and firming the system without new coal or gas (Chapter 4). Two barriers hold utility-scale storage back in Indonesia today: solar + storage remains expensive relative to the coal it competes against, and Indonesia lacks a regulatory framework that lets storage operate and earn its value. Both need to be tackled for storage to scale with the 100 GW solar programme.

The cost barrier is real but can be closed. With four-hour storage, solar-plus-BESS delivers power at around 15 cts/kWh today, against ~3.5 cts/kWh for existing DMO coal (Chapter 2). Three forces can bring the costs of solar + BESS down:

- Global battery system costs have fallen around 16% per year since 2010 and continue to decline (see Chapter 3);
- Because the cost of a solar-plus-storage system is driven by the cost of the solar generation supplying it, the solar LCOE reductions set out in Chapter 3 feed directly into a lower combined cost;
- The same interventions that bring down solar costs apply to co-located storage, which shares the solar project's site and grid connection: lower land-acquisition and grid-connection costs, competitive and predictable procurement, and an updated local content strategy all reduce the combined solar-plus-storage cost.

Lower costs are necessary but not sufficient: storage will not scale until the regulatory framework is updated to value storage. Three gaps stand out:

First, storage is barely defined in regulation today. MEMR Regulation 19/2025 recognises batteries within hybrid plants, but only below 10 MW, and the tariff decree is still being finalised, leaving no commercial framework for standalone or co-located utility-scale storage[158],[159]

Second, there is no ancillary-services market and little grid-code recognition, so batteries cannot be paid for the frequency response, reserves, and peaking capacity they provide, and depend on bilateral deals with PLN[160].

158 ECADIN (2026) MEMR Regulation No. 19 of 2025 and the Role of Hybrid Power Plants in Indonesia's Energy Transition
159 ESS News (2026) Indonesia to announce new government regulation to encourage BESS, hydrogen in remote locations
160 Wibowo et al. (2026) Comparative analysis of grid code recognition of energy storage in Southeast Asian single-buyer electricity systems

Third, there is no dedicated procurement route: operational utility-scale storage is limited to a single flagship project, the 50 MW / 14.2 MWh PLTS IKN plant, directly assigned rather than competitively tendered, plus small pilots[161].

To enable scaling of storage, government can start to (i) define storage as a distinct system asset and extend the hybrid-plant tariff rules beyond the sub-10 MW scope to utility-scale standalone and co-located batteries; (ii) create a revenue route for system services, starting with a capacity or availability payment and a basic ancillary-services mechanism; and (iii) fold storage into PLN's Giga One auction calendar through dedicated solar-plus-storage rounds, which PLN has signalled will follow its first 1,225 MW solar tender[162].

161 Energy-Storage.News (2025) Sembcorp launches Indonesia solar-plus-BESS project with state-owned power company PLN
162 pv magazine (2026) Indonesia tenders 1.2 GW of solar

6.1.4 Category 4: Phased local content strategy to balance domestic manufacturing with cost competitiveness

A phased local content strategy can build Indonesian solar manufacturing up the value chain without raising near-term deployment costs. The core policy mechanism is a time-bound local content requirement (LCR): importers gain temporary access to lower-cost components in return for binding commitments to build domestic capacity at the next stage of the value chain. Each step should be sequenced against the 100 GW deployment trajectory, so that domestic manufacturing scales in step with the build-out. In practice, a requirement at a given stage, cells first, then wafers, then ingots, should take effect only once domestic producers can supply the programme's auction volumes at close to import-parity cost, and it should be announced well in advance so manufacturers have a firm demand signal to invest.

This model already exists in Indonesia. MEMR Regulation 11/2024 allowed imported modules for a defined window, but only from manufacturers that committed to establishing domestic module production by end-2025. This traded short-term cost relief for long-term domestic capacity, and the same mechanism can be replicated for cells, wafers, and ingots in turn.

Indonesia can draw on India's experience [See Box K], which provides a clear success story for progressive upstream integration: module-level requirements first (2021), then cells (2026), then wafers and ingots (2028), with each extension announced years in advance and activated only once sufficient domestic capacity exists. Indonesia's starting point, however, is more advanced than India's was at a comparable stage: it already operates an investment-linked import framework (MEMR 11/2024) and has substantial downstream capacity in place, around 10.6 GW of module and 9.5 GW of cell assembly, though this is heavily underused because domestic demand is currently low[163]. The near-term task is therefore less about building assembly capacity from scratch, as India did, and more about using the 100 GW build-out to absorb this idle capacity

163 SR (2025) Indonesia Must Seriously Develop an Integrated Solar Industry.

before extending requirements to the upstream steps Indonesia still lacks: wafers, ingots, and polysilicon. With the 100 GW commitment approaching, the timing is right to review the LCR so the programme reshapes Indonesia's clean-technology manufacturing landscape.

BOX K | India's domestic solar manufacturing strategy

India's solar manufacturing strategy followed one principle: start by importing components to scale demand, then progressively require domestic production at each step of the value chain, moving from final assembly backwards toward raw materials. At each step, the domestic requirement was only introduced once local capacity could supply the market without a significant cost penalty.

India first allowed unrestricted module imports to scale deployment through competitive auctions. Once market scale had been established, it introduced the ALMM framework requiring domestically assembled modules in government-backed projects from 2021, supported by the Production Linked Incentive (PLI) scheme ~USD 2.8 billion in output-linked subsidies to manufacturers[164]. Module manufacturing capacity grew from 8 GW in 2021 to over 120 GW by mid-2025[165]. The requirement was then extended one step upstream: domestically manufactured cells become mandatory for all eligible projects from June 2026, by which point cell capacity had reached 29 GW[166]. A wafer requirement follows in 2028, but activates only once at least three independent manufacturers with combined capacity of 15 GW are operational[167].

The lesson for Indonesia is not to replicate India's exact sequence, but its principle: let incentives run ahead of mandates, move requirements up the value chain step by step, and do not impose local content faster than competitive domestic capacity can absorb it.

164 IEEFA and JMK Research (2025) Assessing the effectiveness of India's solar Production Linked Incentive scheme
165 CEEW (2025) Unlocking Solar Manufacturing Potential with Solar PV Modules
166 IEEFA and JMK Research (2025) Assessing the effectiveness of India's solar Production Linked Incentive scheme
167 SolarQuarter (2026) MNRE Expands ALMM Framework To Include Solar Wafers, Strengthening Domestic Supply Chain

6.2 Supporting demand-side electrification

As set out in Chapter 2, electrification drives substantial benefits beyond decarbonisation: it reduces oil and gas import dependency, lowers long-run energy costs for industry and consumers, and strengthens export competitiveness. For most sectors the electrified option becomes the lower-cost choice once its efficiency advantage outweighs any price gap between electricity and the fuel it replaces (see Chapter 1), and falling electricity prices bring that crossover forward[168]. The crossover arrives soonest where the displaced fuel is expensive, such as industrial heat based on imported oil, and latest where fossil fuels remain cheap, as

168 Michael Libreich (2026) The Electrification Staircase

with DMO-priced coal, which is why rebalancing incentives and bringing down solar costs both accelerate electrification.

Scaling renewable supply and electrifying demand reinforce each other: higher electricity demand spreads grid and generation CAPEX over more units of consumption and reduces the risk of (temporary) overbuilt capacity, supporting greater scale and further cost reductions in renewables; in turn, lower-cost renewables reduce electricity prices, accelerating the crossover to electrified solutions across transport and industry.

Realising this requires policy action across the two segments where electrification has the biggest near-term impact: transport and industry. The remainder of this section sets out the policy interventions needed in each.

Transport. Indonesia's transport electrification has progressed unevenly across vehicle segments, and the incentive landscape has become increasingly uncertain. Three segments require distinct policy responses:

- **Passenger EVs.** Indonesia's passenger EV uptake was on a strong trajectory until recent policy shifts: the EV market share in new car sales rose from around 1% in 2023 to around 15% in 2025[169,170], driven by rapid global cost reductions and a coherent national incentive package that combined import duty exemptions, luxury tax waivers, and reduced VAT for fully assembled EVs. This framework gave consumers, manufacturers, and investors a clear signal, and the EV market was on track for a step change in 2026 and beyond. The incentive landscape has since been volatile. Import incentives for fully assembled EVs expired at end-2025 and were not renewed, and in April 2026 the government withdrew the nationwide EV tax breaks and passed authority over vehicle tax rates to regional governments[171]. It has since begun reintroducing national support on a new basis: a phased VAT and luxury-tax package, rolled out from mid-2026, restricted to battery EVs and weighted towards locally assembled, nickel-battery models[172]. The direction is right, but terms have changed repeatedly, rollout has slipped, and regional discretion still fragments the market. **The priority is to settle a stable, nationally coherent EV incentive framework and hold it in place long enough to rebuild investor and consumer confidence.**

- **Electric two-wheelers (E2Ws).** While Indonesia is the biggest two-wheeler (2W) market in Southeast Asia, its E2W stock remains at 0.7% of total two-wheelers today, and E2Ws made up only 1.3% of sales in 2025, despite a lower total cost of ownership than combustion two-wheelers (see Chapter 1)[173]. Policy has run in stop-start cycles. A national subsidy of IDR 7 million per unit launched in 2023 was hampered by a complex application process and terminated abruptly in late 2024[174]; replacement schemes promised for 2025 never materialised, and sales collapsed by around 80% in 2025. A smaller subsidy of IDR 5 million per unit, covering an initial 100,000 units, is being introduced in 2026, but its launch has slipped repeatedly and it still awaited its implementing regulation in mid-2026[175]. **The priority is to introduce a stable, targeted, and long-term E2W scheme** rather than year-by-year subsidies subject to political cycles, with two specific levers:

    - First, **structured financing support** to address upfront cost barriers and secondary market issue despite favourable Total Cost of Ownership economics: China's 2025 national consumer trade-in programme provides a working template at scale. The e-bike component of the programme committed RMB 1 billion (approximately USD 140 million) in trade-in subsidies, reaching 1.65 million consumers and triggering 1.66 million new electric scooter purchases within months, with subsidies applied directly at point of sale[176]. Indonesia could adapt this upfront subsidy with dedicated E2W financing windows coupled with de-risking facility aimed at Indonesian financiers that perceive E2W as a zero-value investment at end-of-life stage.

    - Second, **targeted incentives for fleet operators**: Gojek, Grab, and delivery platforms have the highest daily mileage profiles, making the cost-of-ownership case for electric strongest at fleet level[177]. Fleet conversion typically reaches scale several years before private adoption, providing a stable demand anchor for the domestic E2W manufacturing sector.

- **Trucks and heavy-duty vehicles**. Electrification of heavy-duty transport is still at an early stage, but for mining and remote operations it is starting to take off because the cost advantage is increasingly clear. Vale Indonesia signed a strategic cooperation agreement to deploy more electric trucks in April 2026, following a trial of all-electric mining trucks at its Sulawesi nickel sites that reportedly reduced energy costs by over 50%178. Indika Energy's Kideco coal mine in East Kalimantan started EV dump truck trials in September 2024 with Sany179, and mining contractor Saptaindra Sejati received 15 heavy-duty electric trucks in May 2026 following successful trials in tropical mining conditions180. The priority is to scale these early deployments by focusing on off-grid and remote mining operations where high diesel costs make the economics most favourable. Indonesian retail diesel prices reached IDR 26,000 per litre (around USD 1.47 per litre) in May 2026, the highest on record181, and making the operating-cost gap with electric alternatives substantial.

169 IEA (2026) Global EV Outlook 2026
170 A. A. Huda, R. Bridle and A. Suharsono (2025) Indonesian Electric Vehicle Boom: A temporary trend or a long-term vision?
171 Until end-2025, imported completely built-up (CBU) EVs benefited from import duty exemptions, luxury tax waivers (PPnBM), and reduced VAT. From January 2026, these incentives apply only to locally-assembled EVs meeting at least 40% domestic content (TKDN), which retain a 1% VAT rate. The TKDN threshold rises to 60% by 2029 and 80% by 2030.
172 In April 2026 the government withdrew the nationwide EV tax breaks and shifted authority over vehicle tax rates to regional governments (Eco-Business, 2026; ANTARA, 2026). From mid-2026 it began reintroducing national support on a different basis: a government-borne VAT scheme (PPN DTP) of 40 to 100 percent for electric cars, a 100 percent luxury-tax (PPnBM) exemption, and a direct subsidy of IDR 5 million per electric motorcycle, initially covering around 200,000 units and later widened. The support is restricted to BEVs and weighted towards nickel-based batteries and locally-assembled models, with final terms still being confirmed in mid-2026 (Indonesia Business Post, 2026; ANTARA, 2026).
173 IEA (2026) Global EV Outlook 2026
174 A. A. Hermawan (2025) Time to Ride, Indonesia Electric Motorcycle Diaries
175 ANTARA (2026) Indonesia's Rp5M e-motorcycle incentive awaits finance regulation.
176 Mordor Intelligence (2025), China E-Scooter Market Size, Share & 2030 Trends Report
177 IESR (2023) Indonesia Electric Vehicle Outlook 2023
178 International Mining (2026), Boonray signs cooperation deal with Vale Indonesia following successful electric mining truck trial. Trial numbers may not represent actual full deployment of electric mining trucks.
179 Indika Energy (2025), Eco-Innovation in Mining: EV Dump Truck Trials at Kideco
180 Electrive (2026), Indonesia: Sany delivers 15 electric trucks to Saptaindra Sejati
181 GlobalPetrolPrices.com (2026), Indonesia diesel prices, 18-May-2026

Policy levers to accelerate deployment include accelerated permitting for mining operators piloting electric fleets and dedicated concessional finance for the upfront capital premium.

- **Across all three segments, charging infrastructure remains a critical enabler.** Expanding charging and battery-swap networks beyond Java through dedicated public funding for inter-city corridors, combined with interoperability standards to prevent network fragmentation, is essential to sustain the deployment trajectory in each vehicle category .

Industry. The cross-cutting incentive rebalancing set out earlier (phasing down the DMO, HGBT, and other fossil fuel supports, and including captive coal in the ETS) will go a long way to incentivise the switch from fossil fuels to electricity in industry. In addition, CAPEX support and concessional finance for industries switching from fuel-based to electricity-based processes can accelerate this transition, with two reinforcing benefits for the renewable build-out: industrial electrification creates the catalytic on-grid demand needed to absorb additional renewable supply at scale, and industrial sites with on-site solar and storage anchor distributed renewable deployment that complements utility-scale capacity.

Targeting these supports at industries with the strongest electrification economics today (textiles, food and beverage, glass, ceramics) ensures that public capital catalyses both end-use decarbonisation and the renewable generation build-out.



Appendix I:

The land and grid interventions set out in Section 6.1.3 are well precedented internationally. The table below summarises how government and quasi-government entities in seven markets used land acquisition, pre-zoning, and shared transmission mechanisms to unlock renewable deployment, and the outcomes each achieved. These cases informed the intervention options proposed for Indonesia; they are indicative of what integrated state coordination can deliver rather than direct templates, since each reflects its own regulatory and market context.

Country	Vehicle / Programme	Land Intervention	Transmission Intervention	Key Outcome
India	MNRE Solar Park Scheme + SECI (since 2014)	State governments identify and pre-acquire contiguous "wasteland"; CFA grant up to Rs 20 lakh/MW or 30% of project cost[182]	State Transmission Utility builds shared evacuation infrastructure pre-park; CFA covers grid-connectivity cost[183]	50 parks, ~38 GW sanctioned; 5 acres/MW model standardized; tariffs hit historic lows (Rs 2.36/kWh, Bhadla)[184,185]
Australia (NSW)	EnergyCo + Rewiring the Nation + REZ framework	EnergyCo budget includes AUSD 490M for land acquisition and biodiversity offsets in Central-West Orana REZ[186]	A USD 2.1B Transmission Acceleration Facility (NSW) for 2025-2026;[187] AUSD 750M from federal CEFC for CWO REZ transmission[188]	First REZ planning was state-approved 2024; 4.5 GW network capacity by 2028; 35-year concession to ACEREZ consortium[189]

182 International Mining (2026), Boonray signs cooperation deal with Vale Indonesia following successful electric mining truck trial. Trial numbers may not represent actual full deployment of electric mining trucks
183 International Mining (2026), Boonray signs cooperation deal with Vale Indonesia following successful electric mining truck trial. Trial numbers may not represent actual full deployment of electric mining trucks
184 Development of Solar Parks and Ultra Mega Solar Power Projects, MNRE (2025)
185 50 Solar Parks of nearly 37.5 GW sanctioned since 2014; capacity of 10.2 GW established: Union Power and New & Renewable Energy Minister; PBI Delhi (2023)
186 CWO REZ network project - remade revenue determination - summary report; Australia Energy Regulator (2025)
187 "Further $1.8 billion to power NSW to a clean energy future" Media Release, NSW Government (2023)
188 "CEFC commits $750 million to development of landmark NSW energy transformation project" Media Release, CEFC (2025)
189 "Deal is sealed for Australia's first Renewable Energy Zone" Media Release by Ministry for Energy and Climate Change; NSW Government (2025)

Country	Vehicle / Programme	Land Intervention	Transmission Intervention	Key Outcome
South Africa	REIPPPP + IPP Office (DBSA-hosted)	Developer-led but with state coordination; deep-vs-shallow connection cost split[190]	Eskom bears "deep connection" costs (transmission strengthening); IPP only pays "shallow" (to nearest substation)	R209.7bn (~USD 12-20B+, depends on exchange rate) private investment mobilized;[185] 6.4 GW awarded to 112 IPPs; tariffs fell 70% across bid windo[191]
Vietnam	DPPA Decree 57/2025 + EVN + PDP8	Developer-led but with state coordination; deep-vs-shallow connection cost split[192]	Eskom bears "deep connection" costs (transmission strengthening); IPP only pays "shallow" (to nearest substation)	R209.7bn (~USD 12-20B+, depends on exchange rate) private investment mobilized;[180] 6.4 GW awarded to 112 IPPs; tariffs fell 70% across bid windows[182]
Morocco	MASEN (state agency, 2010)	MASEN directly acquires land at scale (3,043 ha for Noor Ouarzazate) and leases to IPPs[193]	Tripartite agreement (Government-MASEN-ONEE) defines transmission terms before tender; existing 225kV line leveraged[194]	~$2.3B for Noor complex; world's largest CSP; first project enabled by single-window state agency

190 South Africa's REIPPP: Success Factors and Lessons, PPIAF/World Bank; Eberhard, Kolker & Leigland (2014)
191 South Africa's Renewable Energy IPP Case Study; Global Infrastructure Hub (2021)
192 South Africa's REIPPP: Success Factors and Lessons, PPIAF/World Bank; Eberhard, Kolker & Leigland (2014)
193 Summary Environmental and Social Impact Assessment (ESIA) for Ouarzazate Solar Power Station Project II; African Development Bank Group (2025)
194 Noor Ouarzazate Solar Complex; Project Webpage; Power Technology (n/a)

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IESR Institute for Essential Services Reform

INDEF | GTi Green Transition Initiative

Energy Transitions Commission

SYSTEMIQ

aplsi Asosiasi Produsen Listrik Swasta Indonesia