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# Electricity market designs in Southeast Asia

## Harnessing opportunities for renewable energy growth in Indonesia, Thailand, Viet Nam, and the Philippines

CASE for Southeast Asia

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### ANALYSIS
Electricity market designs in Southeast Asia: Harnessing opportunities for renewable energy growth in Indonesia, Thailand, Viet Nam and the Philippines

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### About CASE
The Clean, Affordable and Secure Energy for Southeast Asia (CASE) project supports power sector transitions in Indonesia, Thailand, Viet Nam and the Philippines through evidence-based analysis and narrative change. The project supports decision-makers, industry leaders and consumers in enacting strategic reforms in the power sector in pursuit of the Paris Agreement goals and a just transition.

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# Key recommendations

This report assesses opportunities for fast-tracked renewable energy growth in Indonesia, Thailand, Viet Nam and the Philippines. Countries in the region stand to benefit from significant resource potential and high investor readiness but need to consider adjustments to their market and policy frameworks in order to be able to deploy variable renewables at scale and speed. Decision-makers could consider the following interlinked recommendations for the near term to move their power systems towards high shares of renewables.

**Recommendation 1: Increase the volume and frequency of renewable energy tenders, de-risk renewable energy power purchase agreements and unlock private-sector deployment of renewables through corporate PPAs.** In all four countries, investments in renewables must be scaled rapidly to be on track for net zero, reduce energy costs and safeguard energy security. Besides needing greater tender volumes, tender processes require icreased transparency to attract more bidders. Competitive pricing could be introduced into tender designs to lower the cost of wind and solar deployment – as has been adopted in the Philippines. Renewable energy investments should be de-risked by adjusting risk-return allocations in power purchase agreements (PPAs) whose terms favour fossil over renewable assets in the countries in focus. Meanwhile, in an incremental shift away from the single-buyer model prevalent in the region, countries should move forward with ambitions for third-party grid access and corporate PPAs to mobilise private-sector investment and spur renewable deployment rates.

**Recommendation 2: Reform power purchase agreements for fossil assets to value and reward system flexibility.** While grid capacities must increase in order to integrate increasing shares of variable renewables, existing fossil fuel fleets can help countries through the first stages of variable renewable energy (VRE) growth with key system flexibility services. Contractual obligations in power purchase agreements for fossil assets, aimed at securing baseload availability, prevent their flexibility potential from being exploited *cost effectively.* Contractual reform for greater flexibility should be prioritised in all four countries – including in the Philippines, where physical bilateral contractual commitments have undermined the efficiency of centralised wholesale markets. Decision-makers and system operators in Indonesia, Thailand and Viet Nam may also need to consider introducing intraday dispatch schedules and shortened dispatch intervals to reduce reserve requirements for accommodating variable supply.

**Recommendation 3: Halt the addition of fossil fuel baseload power plants and efficiently manage the retirement of inflexible and carbon-intensive assets following a three-step logic: repurpose, reserve and retire.** *1) Repurpose* fossil fuel plants to operate flexibly and accommodate wind and solar energy – providing reactive power and frequency control and fulfilling ramping requirements, supported by PPAs that reward such services. *2) Reserve fossil* fuel plants, leaving them on standby for system contingencies; this will reduce their operating costs to a minimum and create market space for variable renewables to enter the system. *3) Retire* assets with less system value, starting with older, least-efficient power plants.

**Recommendation 4: Establish a new security of supply paradigm based on probabilistic resource adequacy assessments, flexibility needs assessments and state-of-the-art grid planning.** To varying extents, system planners in all four power systems have overbuilt baseload fossil fuel assets over the past decades. This has resulted in high reserve margins and increased power system costs while curbing renewable energy growth. A new security of supply pivot towards renewables, flexibility sources and network development in long-term adequacy assessments and procurement will be critical in enabling Southeast Asian countries to decarbonise power sectors while ensuring affordable electricity. Realistic demand projections should underpin this.

**Recommendation 5: Unlock fossil fuel cost savings for the benefit of consumers while ensuring the energy sector's financial sustainability.** Governments should consider using fiscal measures to support utilities so that they can deliver on the investment requirements for renewables-based transitions. While capital expenditures are set to increase, fuel cost savings from reduced fossil power generation will curb the system costs of electricity over time, benefitting end consumers. In the long run, a move towards cost-reflective tariffs – with appropriate guardrails for vulnerable consumers in Indonesia and Viet Nam – could help utilities drive the transition to renewables and mobilise adequate investments in grids and flexible resources.

Looking beyond 2030, multiple transition routes must be considered for Southeast Asia's diversity of power system arrangements. Though renewables-based transitions can succeed in various design configurations, from state-owned integrated monopolies to restructured competitive markets, they require modifications to deliver on an altered set of objectives. As the share of variable wind and solar generation increases, power systems in the region must undergo adjustments and, in certain cases, broader reform to ensure their designs provide investment certainty for renewables, unlock system flexibility and facilitate dynamic supply-demand interactions. Centralised planning, market competition and combinations thereof each merit consideration against the constraints of political feasibility and shortening windows to reach decarbonisation objectives. What they have in common is a continued role of the state, be it participatory or regulatory, a major role for the private sector to help deliver the vast investments required, and a need for targeted policy instruments to propel the clean technology shift. The scale of power sector decarbonisation in Southeast Asia's growing economies calls for an outcome-oriented pragmatism which underpins this report's assessment.

# Contents

# Executive summary

Southeast Asian power systems have been expanded significantly over the past decades to meet rapid increases in electricity demand and provide reliable services to growing customer bases. Despite the notable successes in system expansion, the rollout of variable renewables has fallen behind other regions and remains below potential. Wind and solar power in Southeast Asia contribute less than five percent of total power generation in most of the region's countries today – with the notable exception of Viet Nam, where this share surpassed 13 percent in 2023. On the back of ambitious planning, conducive policy, market and regulatory arrangements can drive the large-scale deployment of variable renewables. A shift to renewables is set to empower countries, allowing them to benefit from cost-competitive electricity, clean generation profiles and insulation from international market swings in fossil fuel prices.

This report assesses market and regulatory barriers to variable renewable energy investment and system integration in four of the region's leading economies – **Indonesia, Thailand, Viet Nam and the Philippines** – and explores opportunities for fast-tracked renewable energy growth. The assessment and its recommendations build on a review of the countries' electricity market designs, or power system arrangements, and are informed by in-country stakeholder consultations. Annex A of this report provides readers less familiar with the topic with an introduction to electricity market design and the requirements of renewables-based transitions.

Electricity sectors in Southeast Asia span a broad range of configurations: from vertically integrated monopolies to restructured competitive markets, variants of the single-buyer model dominate the market design landscape. This dynamic is reflected in the four countries of focus in this report: Indonesia has an integrated single-buyer system, Thailand operates a ring-fenced single-buyer system, Viet Nam an unbundled single-buyer system with nascent wholesale competition, and the Philippines has a liberalised system with a central dispatch market. Regardless of their form, enhanced market designs for renewables-based transitions should deliver on five interlinked objectives:

1 › Provide long-term investment certainty for variable renewable energies (VREs)
2 › Enhance system flexibility to integrate variable renewables into the system at the least cost
3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs
4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets
5 › Ensure affordable electricity for consumers while maintaining the sector's financial sustainability

These objectives, or pillars, for renewables-ready power systems interact. Too narrow a focus on one can undermine the other. A system-level approach that considers the constituent parts can deliver on each of them in a mutually reinforcing way.

# Differing power systems, similar challenges – and solutions

### Pillar 1 › Provide long-term investment certainty for variable renewable energies

While deployment has been limited to date, the outlook for renewables in Southeast Asia is shifting. Renewables, driven by wind and solar, account for most of the planned capacity additions in all four countries of focus. Their share is slated to increase further as system planners continue to update power supply plans. Nonetheless, renewable capacity additions are not yet on a par with net-zero trajectories and electricity production from fossil fuel sources will continue to increase over the coming years.

The procurement pipeline for variable renewables needs to be expanded dramatically across the region. To successfully achieve large capacities of variable renewable energies, countries must adopt measures that provide revenue certainty and target high upfront investment costs. A de-risked investment profile will lower the cost of financing. This will enable renewable energy projects to recoup investment costs with lower tariffs, benefitting end consumers by providing them with affordable electricity. Two contractual measures are critical: price stability and offtake guarantees. In the four focus countries, fossil fuel assets (i.e. power plants) typically benefit from these de-risking measures, whereas renewables do not or only do to a lesser extent. Scaling procurement and addressing the risk imbalance between fossil and renewable generation technologies in long-term energy contracts are immediate priorities for successful renewable energy growth strategies.

► **Mitigate risk imbalances in long-term contracts for renewables to reduce the financing costs of new projects**
Power purchase agreements (PPAs) are long-term energy contracts that provide revenue certainty to producers and reliable electricity supply to offtakers and consumers. In the four focus countries, the contractual terms in PPAs differ between technologies and tend to expose variable renewables to greater market risk. This includes curtailment risk, exchange rate risk, profile risk (no offtake obligation) and in some cases price risk, from which fossil fuel assets are typically shielded. Decision-makers, regulators and utilities should address the imbalance in risk-return allocations to lower the financing cost of renewables and support their competitiveness. Pay-as-produced PPAs provide price stability and purchase guarantees. They are a suitable contract type for de-risking renewables investment in power systems in the early stages of transition and could be adopted. Revised terms of power purchase agreements for renewable energy projects could be reflected in a standardised template such that developers can factor them into their investment decisions ahead of tender rounds, reducing the transaction costs of renewable energy projects.

► **Scale and optimise renewable energy tenders**
Renewable energy tenders and auctions offer centralised procurement routes that, if designed well, reduce the cost of renewable energy deployment through price discovery and competitive selection. Selected projects or bids typically win a long-term power purchase agreement, providing revenue certainty for financing the investment. The centralised utility procurement of renewables in Indonesia, Thailand and Viet Nam could be streamlined by undertaking the following adjustments: 1) competitive selection based on costs, 2) increased transparency regarding selection criteria, the ranking of offers and their solicitation, 3) a larger project size range to unlock economies of scale, 4) increased frequency to spur deployment and 5) reliable long-term tender schedules. Challenges relating to these dimensions are evident in Indonesia’s and Thailand’s tender schemes. Though Viet Nam updated its renewable energy

tariff design in 2023, it has yet to introduce a project selection mechanism. A well-designed renewable energy tendering scheme would help it meet its ambitious wind power targets for 2030. The Philippines has garnered valuable experience in the competitive procurement of renewable energy. Its auction programme may serve as a blueprint for regional peers but could attract more bidders if project risk factors such as grid capacity were mitigated and price ceilings loosened.

- **Support renewable energy deployment through corporate purchase power agreements**
  Corporate PPAs between investors and large-scale consumers support renewables deployment beyond centralised tenders. Their use, which has proven crucial for variable renewable energy uptake in many systems globally, has been off-limits under single-buyer arrangements where the utility maintains a monopoly on the supply and distribution of electricity. **Third-party access (TPA)** regimes should be established to allow private players to utilise the network and connect new renewable supply with demand from industry and business. This requires the introduction of wheeling charges, which also promise to support utilities in financing grid investments. Viet Nam and Thailand have been taking crucial steps in this direction in 2024, while discussions are underway in Indonesia. Current market arrangements in the Philippines allow for decentral, business-to-business VRE deployment, yet this deserves more attention as a potential key avenue for renewable energy investment.
- **Promote distributed energy resources (DER) with consistent policy incentives**
  Distributed solar energy has considerable potential in all four countries. It provides a demand-side investment opportunity that could accelerate the deployment of renewables and reduce grid congestion costs. Currently, the installation of behind-the-meter solutions (rooftop solar) amount to less than 500 megawatts (MW) in each of the countries and faces substantial hurdles. These include zero compensation for excess electricity, technical restrictions, approval issues or administrative barriers to larger rooftop installations. The Philippines has instituted net metering, while Thai residential consumers benefit from a recently introduced net-billing scheme – from which industrial consumers are excluded. Indonesia and Viet Nam have recently revoked their DER support schemes but do allow investments for self-consumption. An easing of permit requirements, more widespread adoption of net billing, investment support schemes and third-party ownership models could all drive accelerated DER deployment.

### Pillar 2 › Enhance system flexibility to integrate variable renewables into the system at the least cost

Variable renewable energies (VREs) introduce greater supply-side variability into power systems, necessitating flexibility provided by 1) dispatchable generation assets, 2) transmission and distribution networks, 3) storage solutions and 4) the demand side. Key market design features, such as long-term investment signals, short-term dispatch rules and settlement mechanisms determine how potential flexibility sources are utilised in the power system. Their form and function should be evaluated recurrently as the share of variable renewables increases.

The power systems of Indonesia, Thailand, Viet Nam and the Philippines offer considerable potential for integrating new renewable variable supply. First, the four power systems are being expanded to meet demand increases. This allows flexibility to be procured from the outset, preventing the expansion of additional baseload power from fossil fuels. Second, ongoing major grid investments are being considered in most of the systems. This gives rise to an opportunity to align grid expansion plans with the buildout of renewables. Third, the four countries, and ASEAN more generally, are able to capitalise on the availability of cost-competitive storage technologies not available a decade ago. These technologies will be crucial in accommodating VRE surplus and meeting peak demand after sunset, notably in countries such as Thailand and Indonesia that have more solar than wind energy resource potential.

Besides the additional flexibility hardware required over the coming years (see Pillar 4: System adequacy), all four countries can tap into the existing flexibility potential offered by their conventional power fleets to navigate the first stages of VRE growth. Unlocking system flexibility from existing dispatchable generation assets requires commercial arrangements in their PPAs to be aligned with emerging system needs.

- **Repurpose newer and more efficient fossil fuel assets for flexibilit service provisions with adjustments to their long-term power purchase agreements (PPAs).**
  PPAs for baseload power have been instrumental in securing supply in power systems worldwide. In the countries in focus, long-term PPAs for fossil fuel power plants feature generous arrangements that transfer market risk from producers to offtakers and on to end consumers. Initially designed to attract foreign and private investment to help capital-constrained utilities to meet electricity demand growth, the design features of utility PPAs for fossil baseload assets are increasingly at odds with the requirements of renewables-based transitions. This is reflected in their remuneration structure. PPAs in Indonesia, Thailand, Viet Nam and the Philippines include contractual provisions that secure the availability of baseload power through at least one of the following mechanisms: 1) minimum offtake obligations that guarantee the purchase of electricity from fossil baseload assets but may undermine dispatch efficiency by prioritising coal and gas plants over low-cost renewables; 2) capacity payments which guarantee revenue irrespective of electricity production and demand, thereby increasing the system cost of electricity, especially in oversupplied systems. Meanwhile, fossil fuel power plants are expected to provide ancillary services, yet these are not explicitly remunerated – the Philippines addressed this issue by introducing a reserve market in 2024.
  - In **Indonesia**, capacity payments are linked to an availability rating (i.e. readiness to produce) and constitute up to 40 percent of the PPA tariff. In addition, the state-owned utility PLN must run its gas fleet in accordance with its annual and monthly gas offtake contracts, which contain take-or-pay provisions.
  - In **Thailand**, capacity payments are linked to an availability rating and constitute 16 percent of the PPA tariff of conventional power plants. PPAs for gas-fired power plants contain minimum (daily) offtake obligations.
  - In **Viet Nam**, build-operate-transfer projects that do not directly participate in the wholesale market benefit from a minimum offtake guarantee according
    to their fuel supply contract. Standard PPAs and contracts for difference exclude capacity payments and minimum offtake provisions.
  - In **the Philippines**, power plants have physical bilateral contracts and are obliged to participate in the wholesale market. These power supply agreements (PSAs, i.e. PPAs) include capacity payments that are inversely linked to a plant's utilisation rate. This allows coal power plants to receive higher fixed payments when operating for fewer hours, thus keeping revenues stable.

The terms of these contracts must be revisited to reduce power system costs and ensure that existing baseload assets support the integration of variable supply sources.

- **Reduce minimum offtake obligations to increase dispatch efficiency and support the integration of variable renewables.**
  System operators in all four countries use least-cost dispatch models. The dispatch models in Indonesia, Thailand and Viet Nam incorporate offtake commitments stipulated in long-term PPAs. Minimum offtake clauses force the system operator to dispatch fossil fuel power plants according to a predefined capacity factor. They are typically aligned with the utility or independent power producers' (upstream) fuel supply contracts where these contain take-or-pay provisions. Minimum offtake obligations mitigate a power plant's dispatch risk and assure the system operator that sufficient fuel will be available on-site for electricity to be produced and delivered. However, they prevent the system operator from issuing downward ramping orders to power plants, imposing flexibility constraints on power systems. This effect is notable when offtake commitments are defined over daily or hourly periods, as is the case with Thailand's gas fleet. It may lead to situations where the system operator is compelled to curtail variable renewables, overriding their priority dispatch in favour of fossil fuel plants. Minimum offtake obligations must be lowered to unlock the operational flexibility of existing fleets. This could be done by reducing minimum offtake volumes in fuel supply contracts and adopting more diversified fuel procurement strategies – with higher volumeshares of flexible short- and mid-term supply contracts versus long-term supply contracts.
- **Introduce flexibility performance metrics into PPAs for conventional power plants.**
  Long-term contracts in Indonesia, Thailand and Viet Nam do not explicitly put a price on ancillary services, which instead are subsumed under fixed remuneration components. Tying remuneration to flexibility performance indicators (ramp requirements, frequency control, re-active power, spinning reserve) would provide power plant operators with an economic incentive to deliver services in line with system needs. These indicators could transform capacity payments, where such payments are used, into flexibility payments, justifying the costs of a shifting production profile of conventional assets. Alternatively, utilities or system operators could procure flexibility services through separate ancillary service mechanisms or markets, as was introduced in the Philippines in 2024.
- **Wholesale energy markets in Viet Nam and the Philippines offer opportunities to go one step further and replace physical PPAs for conventional power plants with long-term financial contracts.**
  Doing so would expose these producers to short-term market dynamics, optimising dispatch and system flexibility while retaining long-term revenue certainty. **In the Philippines,** physical bilateral contracts are used alongside a mandatory gross pool market, the wholesale electricity spot market (WESM), leaving power producers to bid below marginal costs and undermining dispatch efficiency. Physical bilateral contracts for fossil fuel power plants could be converted to forward financial contracts to 1) mitigate incentives for biased bidding on the spot market while retaining producers' hedged position and 2) remove costly capacity payments. **In Viet Nam**, power plants participating in the wholesale market already use financial contracts for difference for revenue certainty. Nonetheless, physical PPAs cover about half of the country's power capacity – typically foreign-invested build-operate-transfer projects protected by state guarantees and investment treaties. Exposing these assets to the evolving wholesale market would increase the information value of short-run signals and better attune them to the flexibility needs of the power system.

## Pillar 3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs

System adequacy indicates a power system's ability to satisfy demand load at any time with adequate generation, storage and network capacity. With notable exceptions, electricity markets across ASEAN are structurally oversupplied with planning reserve margins (i.e. unused, available capacity at peak load) well above international standards of 10–20 percent. Overestimations of GDP and demand growth and a bias towards over-procurement are the main issues, as utilities have few incentives to optimise costs but are held accountable for the security of supply. As a result, the actual reserve margin in Indonesia's Java-Bali system is roughly 50 percent, Thailand's has tended to hover around 40 percent and Viet Nam's is expected to reach 25 percent in 2025 (73 percent with VRE). In the Philippines, the reserve margins are 35 percent, 44 percent and 82 percent in Luzon, Visayas and Mindanao respectively.

Oversupply in baseload power in Indonesia, Thailand and, to a lesser extent, the Philippines has limited the deployment potential of variable renewables. However, sustained electricity demand growth in all four countries makes oversupply a temporary issue that will pave the way for renewables to supply future demand increases. Of the countries in focus, only Viet Nam has so far been able to capitalise on this opportunity.

- **Utilities and system operators ought to revisit resource adequacy assessments and adopt probabilistic planning techniques**
  to account for increased variability in the system and value supply security provided by variable sources, including distributed energy resources (DERs). This will help ensure a cost-optimised resource mix adapted to high shares of variable renewables.
- **System operators and planners could introduce flexibility needs assessment to procure flexible resources for the mid to long term.**
  As oversupply is resorbed by electricity demand growth, flexible capacity should be procured to ensure power system reliability with increasing VRE shares. Current reserve margins make this a mid- to long-term priority; countries currently have the required backup capacity to ramp up and integrate renewable energy without delay. Flexibility needs assessments would inform investment decisions for a cost-optimised generation mix.
- **Grid reinforcement should be prioritised to support the integration of variable renewables into power systems.**
  Grid and resource planning must be aligned to optimise power systems for high shares of variable renewables. The introduction (or reform) of network tariffs should be considered to provide a transparent revenue model for investments in the transmission and distribution networks and keep up with grid capacity requirements.

## Pillar 4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets

For years, power system expansion in Indonesia, Thailand, Viet Nam and the Philippines has been predicated on a buildout of fossil fuel fleets. This landscape is shifting, with renewables set to lead capacity additions in all four countries. The speed of transition has become the major challenge to be tackled. Its success will rest on whether the pipeline of new fossil fuel assets is reduced and whether the existing fossil fuel fleet is effectively reorganised to support the integration of variable supply sources.

Halting investments in new coal power remains a priority for coal-dominant Indonesia and Viet Nam, which despite JETP objectives plan to add 14 gigawatts (GW) and four GW respectively from approved projects by 2030. The Philippines imposed a moratorium on new coal in 2020, yet several GWs of new coal power are under development. Alongside a large-scale pivot towards renewables, it plans on expanding its gas power fleet. Meanwhile, Thailand is expected to maintain the (absolute) size of its gas fleet on a net basis, with renewables largely supplying incremental demand growth over the coming years.

None of the focus countries have developed detailed coal or gas phase-out plans, which have proven politically challenging to introduce in expanding power systems designed to meet future demand increases. The fact that coal fleets are young further complicates this issue. Fortunately, the existing fossil fuel fleets can facilitate the integration of variable supply sources if they are accompanied by a value shift from baseload to flexibility service provisions (Pillar 2 – System flexibility). The following approach should be considered to optimise the supply mix as renewables are deployed.

► **Halt all capacity additions in coal; render capacity additions in gas-fired power conditional on flexibility performance and system flexibility needs.**
Phase-outs start with the addition of no new fossil power capacity; approved coal power projects – uncompetitive if exposed to market forces – should be cancelled to avoid increased system costs. New gas-fired power capacity should be assessed against the economic viability of clean alternatives such as additional renewables and battery energy storage systems. Flexible gas plants that remain in the power system by the 2040s should be able to shift to 100 percent clean fuel usage, such as renewables-based hydrogen.

► **Phase out carbon-intensive assets following a three-step logic: repurpose, reserve and retire.**
1. **Repurpose existing coal and gas assets to integrate variable renewable energies (VREs).** Identify younger and more efficient assets for repurposing to supply fluctuating net load profiles, supported by adjusted remuneration models (see Pillar 2 – System flexibility).
2. **Reserve assets for contingencies.** Identify assets to be kept as backup for electricity security. A strategic reserve will bypass current overcapacity constraints to renewable energy deployment in the focus countries and ensure security of supply is achieved at a lower cost. It will yield savings in fuel and fixed operation and maintenance costs, while creating market space for renewables to enter the system at greater speed.
3. **Retire carbon-intensive assets with less system value.** Identify the least-efficient assets for early retirement in line with national climate targets. Ongoing financial initiatives, such as the Just Energy Transition Partnership for Indonesia and Viet Nam and the Asian Development Bank's Energy Transition Mechanism, could support the early termination of these assets' power purchase agreements.

Carbon pricing policies, recently introduced in Indonesia and under consideration in Viet Nam, support the economics of retiring carbon-intensive assets. This requires two key conditions to be met: 1) an ambitious policy design is needed that delivers a credible carbon price to which producers are fully exposed, i.e. minimal tax exemptions or free allocation of emissions allowances, and 2) an electricity market design that allows carbon costs to affect a power plant's margins, typically through the combination of cost pass-through and marginal cost dispatch. Electricity offtake obligations, price caps or retail tariff freezes could limit the effect of carbon pricing instruments in Indonesia and Viet Nam and may require contractual reform. Ambitious system planning is more likely to put the power systems in question firmly on track towards low-carbon electricity supply: plan for and procure high (V)RE shares with conducive support measures, introduce a full investment ban on coal power or an ambitious shadow carbon price in investment decisions, and repurpose, reserve and retire the existing fleet.

### Pillar 5 › Ensure affordable electricity for consumers while maintaining the sector's financial sustainability

The success of renewables-based transitions in Southeast Asia hinges on ensuring affordable electricity prices for consumers. End-user electricity tariffs have risen in all four focus countries as a result of rising fossil fuel prices in the period 2021-2024. Reduced demand during COVID-19 also meant that utilities had to recoup their debt service obligations and capital payments to independent coal and gas units with smaller sale volumes, necessitating tariff hikes or government intervention. With lower demand resulting in higher prices, single-buyer systems in the region reached the limits of their ability to respond to shorter-term market fluctuations on account of their long-term contract market structure.

**The Philippines,** which records the lowest GDP per capita income of the countries in focus, has the highest average end-user tariffs, at 22 US cents per kilowatt hour (ct/kWh). This can be largely explained by rising fossil fuel import dependencies and a lack of or low tariff subsidies. Market arrangements in the Philippines see consumers fully exposed to cost increases, whereas producers are shielded from market and dispatch risk by bilateral power supply agreements. The ensuing skewed risk allocation between producers and consumers affects electricity bills and could be addressed by reintroducing a degree of market risk for producers – as can be observed in restructured markets elsewhere. **Thailand**'s retail tariff averages 14 ct/kWh and, like that in the Philippines, is not subsidised. However, the government of Thailand does provide price support or payment flexibility when gas prices affect the affordability of electricity supply. This may at times expose the state-owned utility EGAT to liquidity constraints.

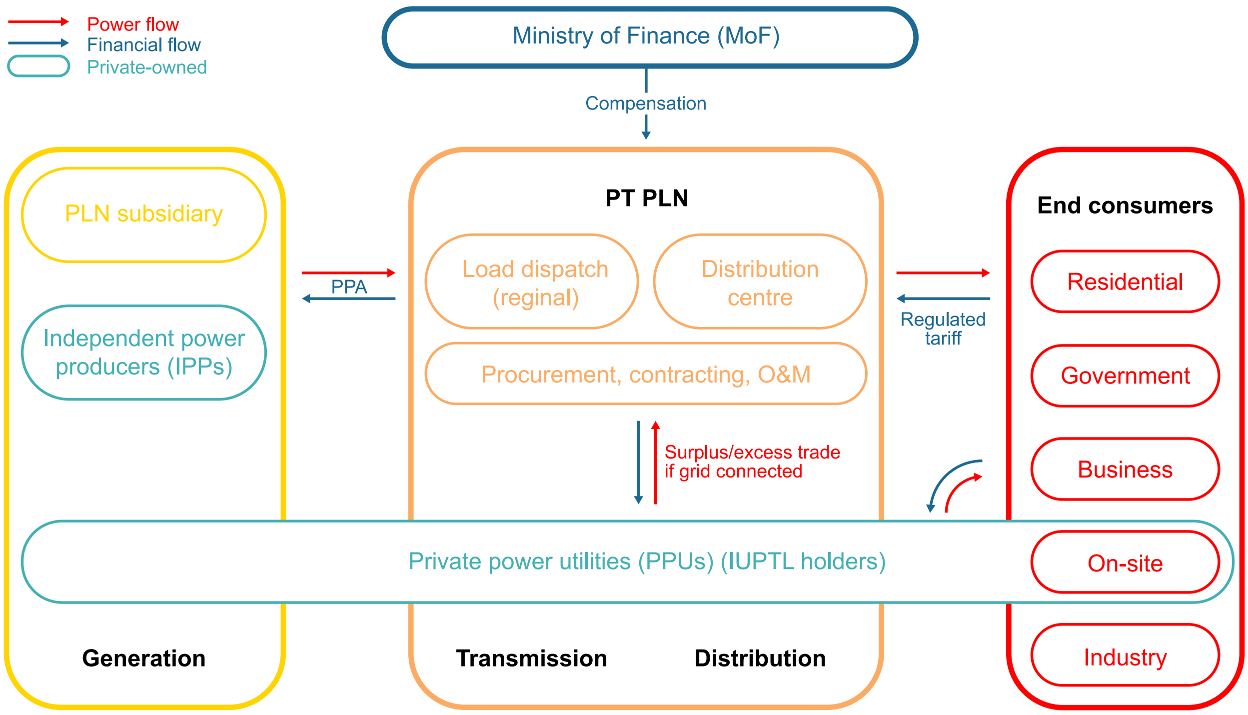
Electricity tariffs average 8 ct/kWh in **Viet Nam** and 9 ct/kWh in **Indonesia.** Both countries subsidise domestic coal supply and maintain below-cost recovery retail tariffs, affecting utility earnings. The government of Indonesia offsets the revenue shortfall with subsidies and compensation payments to PLN. In Viet Nam, the state-owned utility EVN frequently incurs losses when tariff hikes fall behind cost increases. Both tariff regimes affect the public budget and the utility's financial ability to stay ahead of the curve in terms of network development and facilitating greater VRE deployment. While subsidised rates have benefitted consumers, they may come at the cost of quality of service provision if prolonged.

► **Unless governments increase their fiscal support, a shift to cost-reflective tariffs is inevitable if Indonesia's and Viet Nam's utilities are to drive the network investment needed for a large-scale renewables transition.**
Cost-reflective tariffs will remove the strain on the public budget in keeping utilities afloat. A politically charged issue, potential tariff increases must include safeguards for vulnerable consumer groups. Policymakers have multiple options at their disposal, from electricity tariff rebates to household investment support schemes for solar rooftop PV and energy-efficiency support measures.

- **Rebalance the allocation of market risk exposure between electricity producers and end consumers.**
  Power purchase agreements for fossil fuel assets include terms that transfer volume and price risk to the offtaker. Capacity payments to coal plants in the Philippines and Indonesia secure revenue and shield them from competition (dispatch risk) and stranded asset risk. This risk is transferred to the utility and then passed on to end consumers or taxpayers. With the over-procurement of fossil baseload power, the (sunk) cost of idle baseload capacity is socialised. A complete moratorium on new baseload PPAs is the sensible way out of this lock-in situation. In parallel, policymakers could consider options for modifying the terms of current contracts before they expire to maximise the operational flexibility provided by fossil fuel fleets (Pillars 2 and 4) or introduce an acceptable level of market risk for baseload assets.
- **Indonesia, Thailand, Viet Nam and the Philippines can unlock significant fuel cost savings by increasing the share of variable renewables in the supply mix, benefitting consumers through affordable electricity rates.**
  Lower planning reserve margins and optimised generation mixes for variable supply can further reduce system costs – benefitting consumers and the public budget.

# Status quo and priorities for renewable energy growth

### Indonesia – an integrated single-buyer system



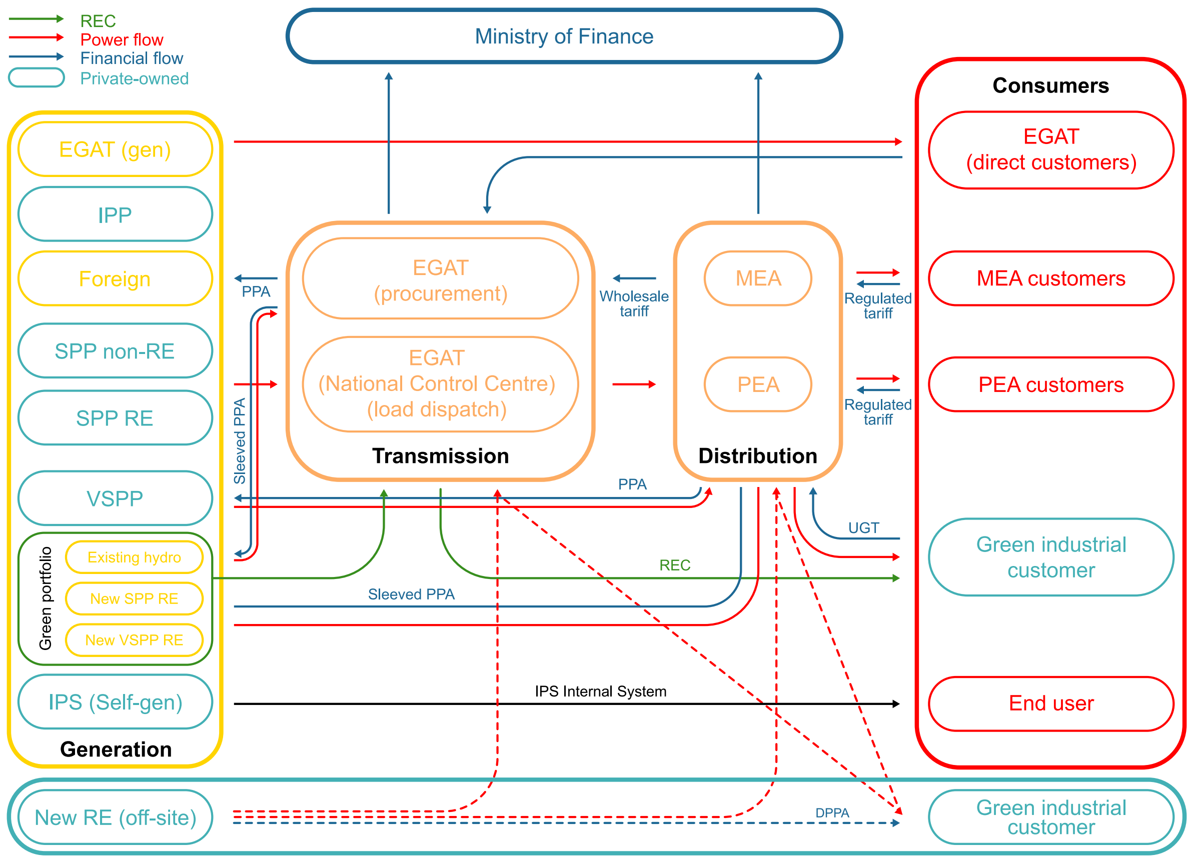

Indonesia's power system relies on coal for two thirds of its generation output. Dispatchable renewables delivered approximately 13 percent of total generation in 2022, whereas VREs delivered less than 0.2 percent. In Indonesia's integrated single-buyer system, power generation is separated from mid-and downstream activities (transmission, distribution, retail), which are integrated within PT PLN. The private sector participates in electricity generation through independent power producer (IPP) and public-private partnership (PPP) arrangements, with long-term contracts concluded with PT PLN. Attempts at market reform in the 2000s were held back on constitutional grounds, with subsequent rulings upholding the sector's monopoly structure. Besides PLN, more than 60 private power utilities serve on-site industrial demand or small community areas beyond PLN's network. PT PLN dispatches generation sources a day ahead according to their submitted schedules and ranking in the merit order.

**Market and regulatory barriers to variable renewables in Indonesia**

- ► The upstream coal industry has a domestic market obligation to supply demand sectors in Indonesia at a capped price. In keeping coal well below international market prices, this instrument understates the cost of dispatching coal plants, encouraging their utilisation and deployment in the system. Fixed capacity payments to an oversized coal fleet further limit VRE deployment.
- ► Renewable energy tenders are infrequent and small in volume. Direct bilateral procurement between producers and large-scale consumers is not (yet) possible.
- ► Renewable energy ceiling tariffs continue to be indirectly linked to the average cost of electricity generation, which is largely comprised of the costs of operating subsidised coal plants. As a result, renewables have had to outcompete subsidised coal plants.

- Power purchase agreements expose renewable producers to greater market risk (volume and price risk) than coal power producers, which furthermore benefit from separate capacity payments to recoup capital costs.
- PLN is capital-constrained and relies on private investment to meet demand. However, renewable energy investors face transaction costs from protracted contract (PPA) negotiations and project risk from PLN co-ownership requirements, which result in renewable energy investors having to mobilise more capital up front for less equity.
- Local content requirements for solar PV have increased deployment costs, while a small procurement pipeline has constrained domestic manufacturers in achieving economies of scale. Import restrictions were eased in 2024, though only for a limited time window.

### Thailand – a ring-fenced single-buyer system

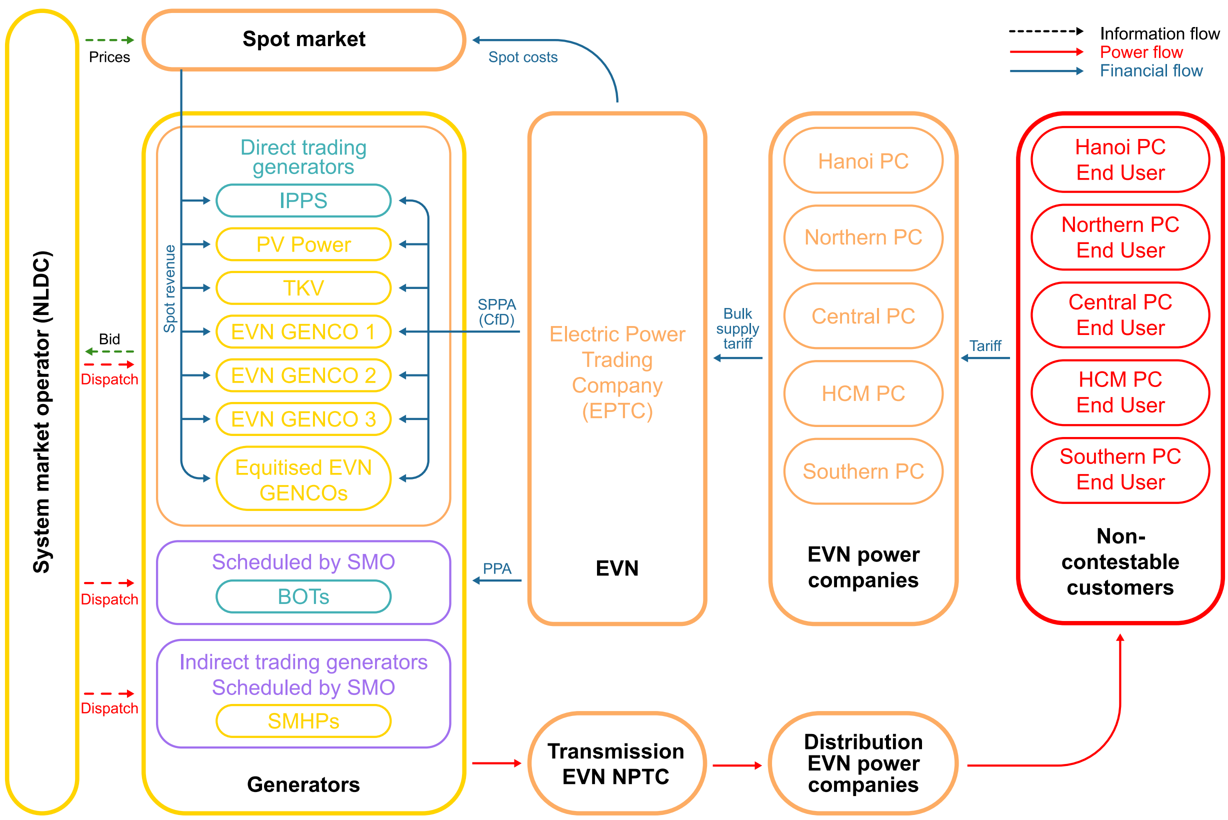



In Thailand's power system, gas-fired power plants delivered 53 percent of generation output in 2022. Dispatchable renewables contributed ten percent, while production from variable renewables comprised less than four percent of total electricity generation. Thailand's electricity sector is structured along three state-owned utilities: one integrated transmission system operator (EGAT) and two integrated distribution system operators (MEA and PEA) that each own and operate the network, and procure, sell and deliver energy to consumers – a triple-buyer or "enhanced single-buyer" system. MEA and PEA procure energy from smaller assets – very small power producers (VSPPs) – including renewable energy resources. EGAT owns generation assets and procures energy from larger assets: small power producers (SPPs) and independent power producers (IPPs). EGAT has ring-fenced its system operator responsibilities. Its National Control Centre dispatches plants according to technical, contractual and economic parameters in the following order: must run (critical for system security); must take (gas power plants with minimum offtake requirements); merit order (remaining capacity ranked according to marginal cost). Debate on Thailand's future electricity market model has reignited in recent years. In a cautious shift away from the prevailing single-buyer system, the government confirmed in 2024 that it would introduce third-party grid access and direct PPAs, which promise to create new investment opportunities for renewables beyond public tenders if properly scaled.

**Market and regulatory barriers to variable renewables in Thailand**

- Thailand's gas-fired power fleet puts the system in a good position to integrate growing shares of variable supply. However, minimum offtake requirements limit gas-fired power plants' operational flexibility and may result in their being prioritised over VRE sources.
- VRE deployment rates so far rely on the government's discretion in launching new tender rounds. While this entails opportunities to deploy renewables in a coordinated manner, the frequency and (capacity) size of tenders are not on a par with a net-zero trajectory and need to be scaled.
- VRE tenders are limited to small projects (< 90 MW) and do not benefit from the economies of scale of larger utility-scale projects. Meanwhile, the awarded tariffs are fixed ex-ante. This means missing out on the cost savings that reverse auctions could deliver. The curtailment risk should also be addressed to increase investor confidence and accelerate technology deployment.
- Support for distributed energy resources (DER) such as on-site rooftop solar needs more attention given the prevailing policy and technical barriers, including zero export rules for industry and the obligation to install export controllers or reverse power relays. With high demand for DER solutions from industry and business, Thailand is set for rapid decentralised solar energy deployment if these restrictions are lifted.

## Viet Nam – an unbundled single-buyer system with limited wholesale competition




Viet Nam's power system relies on coal for 45 percent of its electricity output. Renewables delivered approximately 44 percent of total generation in 2022, including over 12 percent from VREs. EVN, the country's utility, is legally unbundled with separate entities along the value chain, including for market operations. A one-sided cost-based pool market (a generators' market with benchmarked prices) started operating in 2011, with the Electric Power Trading Company (EPTC) being the sole offtaker of electricity. The Viet Nam wholesale energy market (VWEM) is set to transition into a two-sided price-based pool market in the coming years, with demand-side bidding and greater price discovery. This market arrangement promises to better reflect actual system conditions and the short-run value of electricity.

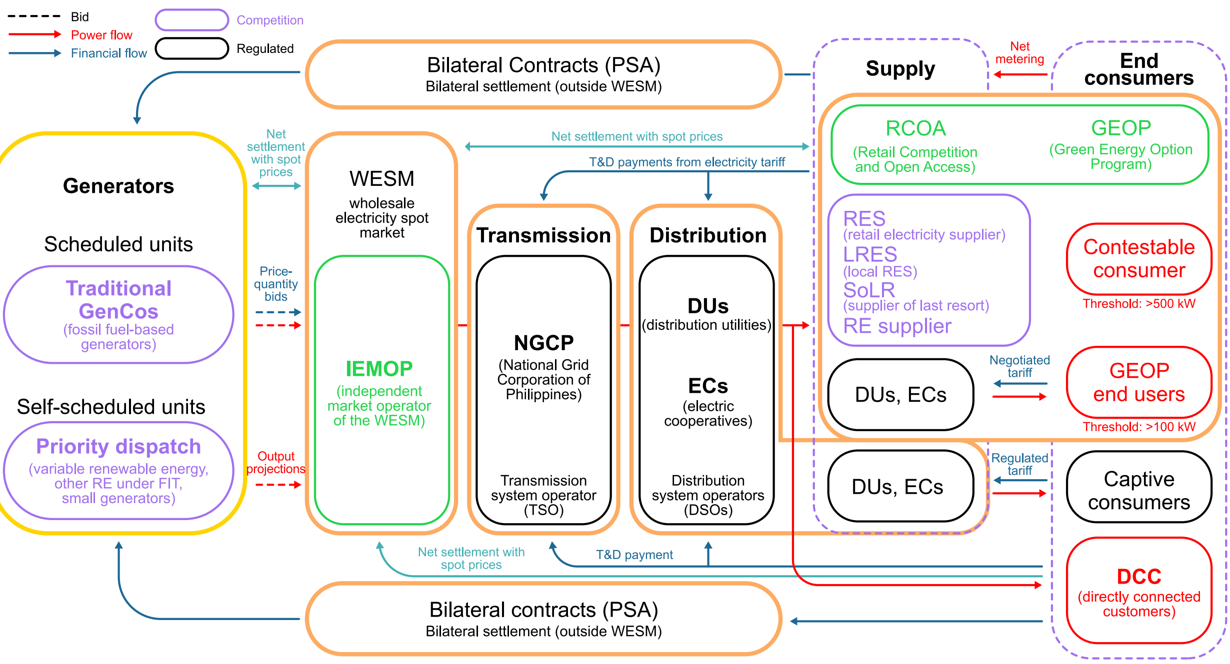
Under the current arrangement, EVN's generation assets participate directly in the wholesale market.  Approximately 60 percent of generators, including RE producers and build-operate-transfer (BOT) projects, remain indirect participants in the wholesale market. NLDC, the system and market operator, places bids on their behalf. NLDC dispatches plants according to market clearing and EVN's contractual offtake obligations, typically towards BOT assets. It also schedules EVN's strategic multi-purpose hydropower plants, based on a water valuation model that optimises their utilisation for energy and ancillary services.

The government introduced corporate PPAs or direct power purchase agreements (DPPA) in 2024, which enable renewable producers to directly sell their output to large consumers. They can do so via bilateral contracts with consumers or via forward contracts on the exchange. The DPPA scheme promises to improve the investment climate for renewables. However, several market barriers remain and need addressing to support the deployment of variable renewables on the scale envisaged by system planners.

**Market and regulatory barriers to variable renewables in Viet Nam**

- A stop-and-go approach to policy support for variable renewable energies has held back investment since the feed-in tariff regime expired in 2021. The introduction of bilateral agreements (DPPA) addresses the regulatory uncertainty that arose to a certain extent. However, it is recommended that the government introduce a new tendering scheme alongside bilateral contracts to increase renewable energy deployment rates and attract sufficient investment.
- While VREs benefit from priority dispatch, this operational practice is not formalised. Curtailment risk has risen due to grid constraints. RE projects are not compensated for curtailed hours, which increases project risk and undermines renewable energy investment.
- Input subsidies for domestic coal understate the cost of dispatching coal plants, encouraging their utilisation and deployment in the system.
- The transmission network has reached the limits of its ability to integrate renewable energy from the southern provinces to supply load centres in the north. It requires expansion to accommodate increased VRE shares. EVN is unlikely to be able to make the requisite investments on its own and may need to involve third parties, underscoring the need for network tariff reform.

## The Philippines – a restructured system with market competition




At 58 percent, baseload coal power dominates the Philippines' electricity supply. Dispatchable renewables delivered 17 percent of total electricity generation in 2022, variable renewables about three percent. The Philippines' power system is liberalised and employs a mandatory one-sided gross pool (i.e. a centralised dispatch) market, the wholesale electricity spot market (WESM) and a bilateral contracts market. The WESM employs a security-constrained economic dispatch model that accounts for the transmission constraints, losses and technical characteristics of the power system to determine the dispatch schedule for each five-minute trading interval. Utilities and retail suppliers have so far been passive participants in the market, but demand-side bidding is expected to be introduced in the coming years. The WESM and the bilateral contracts market are not yet sufficiently streamlined. Market rules require producers to offer all their capacity on the spot market, regardless of their bilateral contractual positions. This has created a perverse incentive among producers to bid below marginal costs on the WESM in order to be dispatched and meet physical bilateral commitments, thereby undermining dispatch efficiency and distorting the market price signal. Potential distortionary effects on renewables have been mitigated through priority dispatch arrangements. Meanwhile, the introduction of intraday dispatch at five-minute intervals in 2021 and a reserve market in 2024 should provide adequate short-term value signals to manage greater shares of VRE.

**Market and regulatory barriers to variable renewables in the Philippines**

- Despite WESM's optimised dispatch model with high spatial and temporal granularity and intraday unit commitments, current interactions between WESM and physical bilateral contracts lack market efficiency and are likely to undermine the least-cost system integration of VREs. This could be tackled by 1) moving to a fully centralised dispatch model, removing bilateral delivery and offtake obligations, or 2) a self-dispatch model, turning the WESM into a voluntary net pool market.
- Relatively high electricity prices stem in part from generous arrangements for fossil baseload assets. Fossil baseload power producers are hedged against dispatch risk, receiving higher fixed payments when running fewer hours. These costs are passed on to end consumers. Tackling price affordability for end consumers may require a manageable degree of dispatch risk to be shifted from consumers to fossil baseload assets, as can be observed in restructured markets in other countries.
- Uncertainty surrounding grid capacity and price caps on renewable energy projects resulted in the GEA-2 2023 auction round of the otherwise successful Green Energy Auction Programme being undersubscribed.
- Grid investments are not keeping pace with technology deployments, delaying the commercial operation date of winning renewable energy projects in the Green Energy Auction Programme and limiting the number of otherwise feasible projects.
- Limited investment outside the Green Energy Auction Programme: despite a comprehensive policy framework and facilitating market regulations, the private renewable energy market for large- and small-scale consumers is still in its infancy, pointing to governance challenges that will need to be tackled for solar energy to be deployed at greater speed.

# 1 Introduction

Southeast Asian power systems have undergone remarkable growth over the past decades to meet rapid increases in electricity demand and provide reliable services to expanding customer bases. Despite the notable successes in system expansion, the rollout of variable renewables falls behind other regions and remains below potential. This report provides a detailed overview of the electricity market designs in four leading economies of the region – Indonesia, Thailand, the Philippines and Viet Nam. It assesses barriers to renewables investment and system integration and explores market and policy opportunities for fast-tracked renewable energy growth.

In 2023, variable renewable energy (VRE) accounted for less than five percent of electrical output in all ASEAN member states but Viet Nam, whose share reached 13 percent – on a par with the global average (Ember, 2024). The only marginal deployment of wind and solar power to date contrasts sharply with the backdrop of political ambition to reach net-zero emissions by mid-century or soon after, significant technical resource potential across the region and major declines in costs, with VREs outcompeting conventional assets. To reach climate goals, the region's renewable energy share must reach 50 percent by 2030, with wind and solar power accounting for at least 25 percent of total electricity generation (Agora Energiewende, 2023). For countries facing constraints in expanding hydropower capacity, the requisite share of VREs is likely to be markedly higher (IEA, 2022a). Electricity sectors in Southeast Asia need conducive market and policy arrangements that enable the large-scale entry of variable renewables and empower countries to capitalise on their cost competitiveness.

The transition to renewables-based systems presents Southeast Asian jurisdictions with a dual investment and system transformation challenge: investment in renewable technologies needs to increase dramatically to meet the growing demand for electric power and progressively displace fossil fuels; electricity networks need upgrading and expansion to accommodate a shifting technology mix and use pattern; and electricity systems must embed greater flexibility in their daily operations, including demand-side participation, to integrate variable supply. Existing electricity market designs ought to be revisited against these emergent priorities and adjusted such that they facilitate the impending technology shift.

From the outset, market designs for renewable energy growth must deliver I) credible long-term investment signals that provide certainty to investors and help reduce capital costs; II) short-term signals that guide the behaviour of flexible producers, consumers and supplier(s) in accordance with evolving system needs; and III) phase-down trajectories for carbon-intensive assets. Furthermore, in line with traditional system objectives, market designs must ensure IV) system reliability and long-term resource adequacy and V) affordable electricity for consumers.

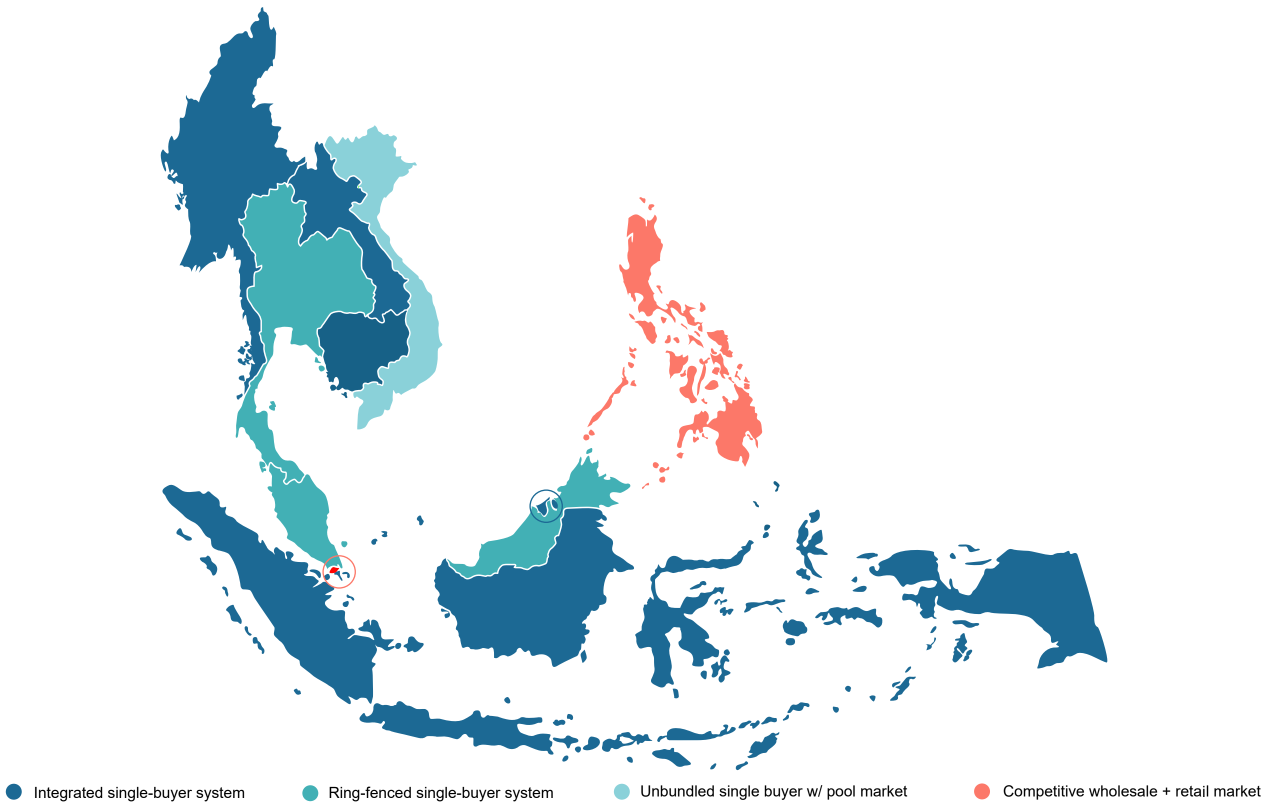
Building on this set of outcome-driven principles, this report reviews the market designs in the four countries and explores policy and market opportunities for building out renewables at scale and pace. The assessment is informed by in-country stakeholder consultations with utilities, regulators, policymakers and power producers. It does not advocate a target model for the countries in focus but acknowledges path dependency in power system transformation. As such, The report identifies opportunities for VRE growth that build upon existing structural and institutional features.

The following chapter examines the electricity market design landscape in Southeast Asia. Chapters 3 to 6 analyse the power system arrangements in Indonesia, Thailand, the Philippines and Viet Nam and identify barriers to and opportunities for renewable energy investment and cost-effective system integration. The chapters close with recommendations for accelerated renewable energy growth towards 2030. The executive summary provides a cross-country synthesis of the analysis. Annex A provides readers less familiar with the topic with an introduction to electricity market design and the requirements of renewables-based transitions.

# 2 Electricity market designs in Southeast Asia

Electricity sectors in Southeast Asia span a broad range of market models, from vertically integrated monopolies to restructured competitive markets. Among the ten ASEAN member states, Singapore and the Philippines currently operate a competitive wholesale energy market. The other eight jurisdictions – including Indonesia, Thailand and Viet Nam – have adopted hybrid market or single-buyer models that manage the entry of private power producers through centralised power purchasing agreements. In these systems, state-owned utilities retain a significant share of generation assets, own and operate the grid and sell electricity to consumers either directly or via their subsidiaries. Figure 1 presents a categorical overview of the region's market models based on their degree of restructuring and competition.

**Figure 1. › Electricity market models in Southeast Asia**




*Variants of the single-buyer model dominate the market design landscape in Southeast Asia, featuring limited competition, regulated entry of private capital and influential state-owned utilities.*

The market designs in ASEAN jurisdictions emerged as a state-led development response to the power market reform agenda of the 1990s. Initially adopted in the Americas and Europe following a wave of liberal economic policies that favoured market competition and a more limited oversight role of the state across the economy, the power market reform package was promulgated internationally as part of a broader economic development paradigm. The textbook reforms prescribed at the time encompassed four mutually reinforcing components (Foster et al., 2020): i) the creation of an independent regulator without commercial interest in the sector; ii) restructuring of the utility through corporatisation and, subsequently, vertical and horizontal unbundling; iii) private sector participation in generation and distribution through third-party access, price deregulation and network regulation; and iv) the introduction of competition through wholesale energy markets. Taken together, these measures sought to induce greater organisational efficiency, mitigate opportunities for political interference, reduce subsidies and system costs and unlock new financing opportunities from the private sector.

While the concerted push precipitated a wave of power sector reforms globally, countries did not uniformly adopt the textbook model. The liberal reform package required high-level political commitment to market-oriented reform strategies and the mobilisation of broad sectoral stakeholder support to overcome vested interests in the status quo (Erdogdu, 2014). In many countries, high infrastructure requirements for power system expansion meant that retaining state ownership and a certain degree of supply chain integration was considered necessary to ensure low-cost financing, revenue certainty and economies of scale.

Instead, the majority of emerging economies selectively adopted elements of the textbook reforms, resulting in the array of hybrid systems observed today. These included establishing a separate regulatory entity and opening the generation segment to independent power producers (IPPs); two elements whose implementation did not involve profound structural reforms but did enable countries to attract much-needed private sector investment (Victor & Heller, 2007). The single-buyer model emerged out of this adapted reform package. Its defining feature is a centralised purchasing arrangement, often through a single, state-owned entity responsible for aggregating load, procuring electricity and selling wholesale electricity to consumers or distribution companies (Arizu et al., 2006). Initially endorsed as a transitionary design ahead of farther-reaching market reforms, the single-buyer model has withstood the test of time, proving to be a durable model in its own right. Variants of it have emerged over time that differ in their degree of unbundling, ownership structures and procurement and contractual arrangements:

- **Vertically integrated single buyer:** An integrated utility acts as the single buyer of electricity and procures energy from independent power producers through long-term contracts, or power purchase agreements (PPAs). This arrangement, also known as the IPP model and widely adopted in Southeast Asia, largely retains the sector's preexisting institutional structure. Indonesia's power system arrangement falls in this category.
- **Unbundled single buyer:** An unbundled utility acts as the single buyer of electricity. The utility's generation assets are separated from transmission and distribution, either through ring-fencing (functional/account unbundling), the creation of subsidiary companies (legal unbundling) or the selling off of assets (ownership unbundling). The purchasing and procurement functions are typically part of the system operator's mandate or fulfilled by a (legally) separate market operator or single-buyer entity. The single buyer procures energy through long-term contracts (PPAs). The key benefit of this approach is reduced bias towards dispatching the utility's assets. Within ASEAN, Viet Nam, Thailand and Malaysia use variants of the unbundled single-buyer system.
- **Unbundled single buyer with a generators' pool market:** Ring-fencing of single-buyer activities and the legal unbundling of the utility provide opportunities for introducing wholesale competition among generators with a single offtaker of electricity. One-sided pool markets can be price- or cost-based and help optimise dispatch schedules by offering greater flexibility in unit commitment. This type of arrangement is currently in use in Viet Nam and, beyond ASEAN, in Korea.

Single-buyer systems with long-term energy procurement induce competition for the (monopolistic) market, be it through direct contract negotiation or a competitive procurement process. Unbundled single-buyer systems with a one-sided pool market further induce competition among producers in the market. The latter paves the way for a transition to bilateral trading between producers and distribution system operators and in subsequent stages between producers and (large) consumers and suppliers, where deemed appropriate. A key requirement for a shift to energy trading between multiple buyers and sellers is for electricity tariffs to be cost-reflective to ensure the creditworthiness of market participants, mitigate default risk and attract investment. In ASEAN's single-buyer systems, governments have typically managed counterparty risk by issuing state guarantees for the public utility, thereby reassuring foreign investors entering into contracts with it and facilitating the inflow of capital.

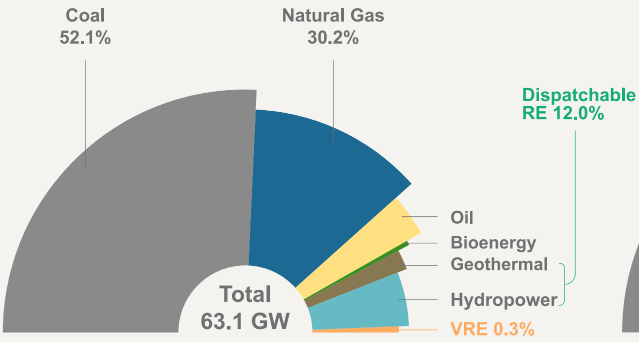
Single-buyer systems tend to be successful in mobilising private-sector investment. A systematic review by the World Bank found that hybrid market systems also performed well in terms of system reliability, energy access and affordability, though less well in terms of cost recovery (Foster & Rana, 2020). To a large extent, the success of single-buyer systems has been predicated on a transfer of (investor) risk and (consumer) cost to a public entity and, ultimately, the government. However, their success has often come at the cost of potential conflicts of interest, contingent liabilities on the government and, with notable exceptions, weak performance with respect to least-cost planning and cost-effective capacity procurement – thereby missing out on possible cost savings (Lovei, 2000; Thomas, 2012). Furthermore, the single-buyer systems in Southeast Asia have underperformed in transitioning to a low-carbon technology mix. When it comes to renewables deployment, countries typically face a number of the following challenges:

- **Utility business model:** Incentives and pricing regulations may not be conducive to VRE uptake. Utilities typically shoulder the costs of balancing the system and may see their assets' capacity factors decline as renewables enter the system. At the same time, network investments may not keep up with grid needs under strained financial conditions.
- **Contract structures:** Contractual terms in utility power purchase agreements, such as capacity payments or offtake obligations, may lock fossil fuel assets into the system and prevent investment in more cost-efficient renewable energy technologies.
- **System operations:** Dispatch operations may need adjustments to deal with greater supply-side variability. This typically involves moving dispatch decisions closer to real-time, introducing enhanced forecast models, establishing cost-effective reserve power procurement and making optimal use of existing technical flexibility potential.
- **Flexibility procurement:** There may be a lack of investment and price signals for flexible resources or of adequate ancillary service remuneration mechanisms, missing out on opportunities for a cost-effective asset portfolio geared to integrating variable renewables.
- **Utility procurement of renewables:** Tender mechanisms may need more transparency, long-term certainty and accessibility to attract a greater number of investors and lower the transaction costs of doing business.
- **Market regulations:** Opportunities for investing in renewables are typically limited to (central) utility procurement mechanisms. Without third-party network access, renewable energy producers and consumers cannot conclude bilateral purchase contracts. This limits the growth of nascent private renewable energy markets.
- **Planning:** Limited incentives for cost optimisation, high reserve margin criteria and the use of deterministic resource adequacy assessments in a centralised planning cycle may result in an oversupply of (predominantly) baseload power, curbing the growth potential for renewables.

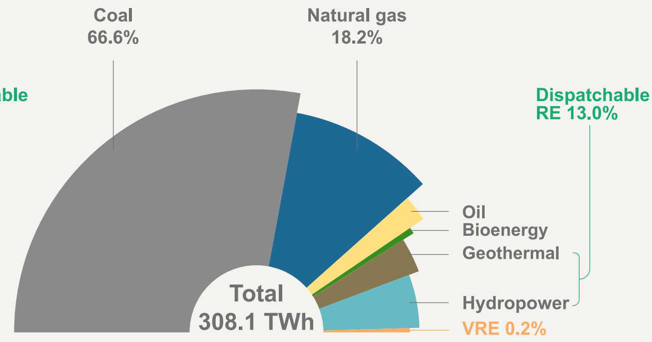
Though single-buyer systems need not undergo a sweeping reform process to tackle these challenges, they can benefit from targeted measures that encourage system flexibility and remove market entry barriers to mobilise investment. This may involve opening up selected areas for competition, tariff and policy reform and introducing new or more effective incentive regulations. Countries with state-controlled electricity sectors stand to benefit from novel hybrid arrangements that strike the right balance between state and markets to reap the advantages of low-cost renewables while maintaining supply security and system reliability.

Priorities for the Philippines' power system differ in key respects from single-buyer systems in the region. Like other ASEAN member states, the Philippines is facing challenges with respect to grid investments, grid connections and an overreliance on coal power (Navarro, 2022). Yet, with fewer domestic energy resources of its own, the Philippines is more heavily exposed to international commodity market swings than its peers. And, as one of the few market-based power systems in the region, its transformation pathway will be different. The Philippines' electricity market design combines elements of central and self-dispatch models. This has resulted in market and dispatch inefficiencies that must be addressed while VREs are deployed. The system could also benefit from new price signals for forward contracting and flexibility procurement – complementing the recently introduced reserve market. The experience of the Philippines may inform challenges in neighbouring countries in several ways: the Philippines is pioneering competitive renewable energy procurement through its green energy auction programme, uses locational signals to dispatch generation assets and has garnered years of experience in bilateral contracting, which remains an area of interest to other jurisdictions in the region.

# 3 Indonesia - an integrated single-buyer system




**Installed generation capacity in 2022**




**Electricity generation in 2022**

**0.78**

**Grid emissions factor ($tCO_2e/MWh$)**

Source: EDGAR, 2023; MEMR, 2022; JEPT, 2023; Statista, 2024.

### Table 1. › Overview of key findings for Indonesia*

| | Enabler | Barrier |
|---|---|---|
| **Investment certainty for variable renewables** | • PR 112/2022 introduced technology, location and project factors to the determination of RE tariffs<br>• Bankable PPAs, but transaction costs in reaching agreement<br>• Favourable tax and import duty regime<br>• Availability of financial capital | • RE tariffs cannot exceed the average (subsidised) cost of electricity<br>• Unequal market risk allocation in PPAs for renewables versus fossil plants<br>• Absent third-party grid access, RE deployment has been limited to tender rounds<br>• Tender rounds are infrequent and small |
| **System flexibility and VRE integration** | • Priority dispatch for VREs<br>• The capacity payment structure of coal PPAs presents opportunities for introducing flexibility payments<br>• Intraday flexibility from gas power fleet | • Capped domestic coal prices understate real cost of dispatching coal plants<br>• No remuneration model for flexibility sources<br>• Network investments must increase but the current utility business model imposes constraints |
| **System adequacy** | • High potential for RE deployment outside the Java-Bali system to meet demand growth | • Oversupplied generation market until 2030 limits space for RE deployment |

| | Enabler | Barrier |
|---|---|---|
| **Phaseout of carbon-intensive assets** | • On-grid coal plants cannot operate beyond 2050 | • 14 GW of new on-grid coal capacity to come online between 2021 and 2030<br>• Loose regulations for captive coal power whose capacity is set to increase |
| **Affordability** | • Price and input subsidies have ensured that electricity tariffs for end consumers are among the lowest in ASEAN but saddle the government with liabilities that must be recovered elsewhere<br>• Variable renewables continue to be perceived as costly by key stakeholders | |

*recommendations are provided at the end of the chapter

Indonesia's electricity sector has retained key features of the traditional utility business model, with limited reforms having been implemented over the past decades. Perusahaan Listrik Negara (PLN), the state-owned utility, was established in 1965 and has since held a monopoly position in the transmission, distribution and retail sectors, as well as a dominant position in electricity generation. With the entry of IPPs in the 1990s, Indonesia's power system adopted a single-buyer model. Energy purchasing and procurement activities have remained fully integrated within PLN's corporate structure. Attempts at market reforms in the early 2000s were thwarted on constitutional grounds, reflecting the preponderance of Indonesia's state-led development approach but also the politicised nature of the sector's transformation pathway. PLN became a state-owned limited liability company in 2004: PT PLN. It underwent another restructuring process in late 2022, transforming it into a holding company with four sub-holdings, each with multiple subsidiaries. Discussions on the future structure of PLN have been ongoing, with a recent report by the Asian Development Bank outlining a roadmap for restructuring the company with the idea of creating an independent single-buyer model with competitive procurement and cost-reflective tariffs (ADB, 2023). As of 2024, no official decision on this had yet been announced.

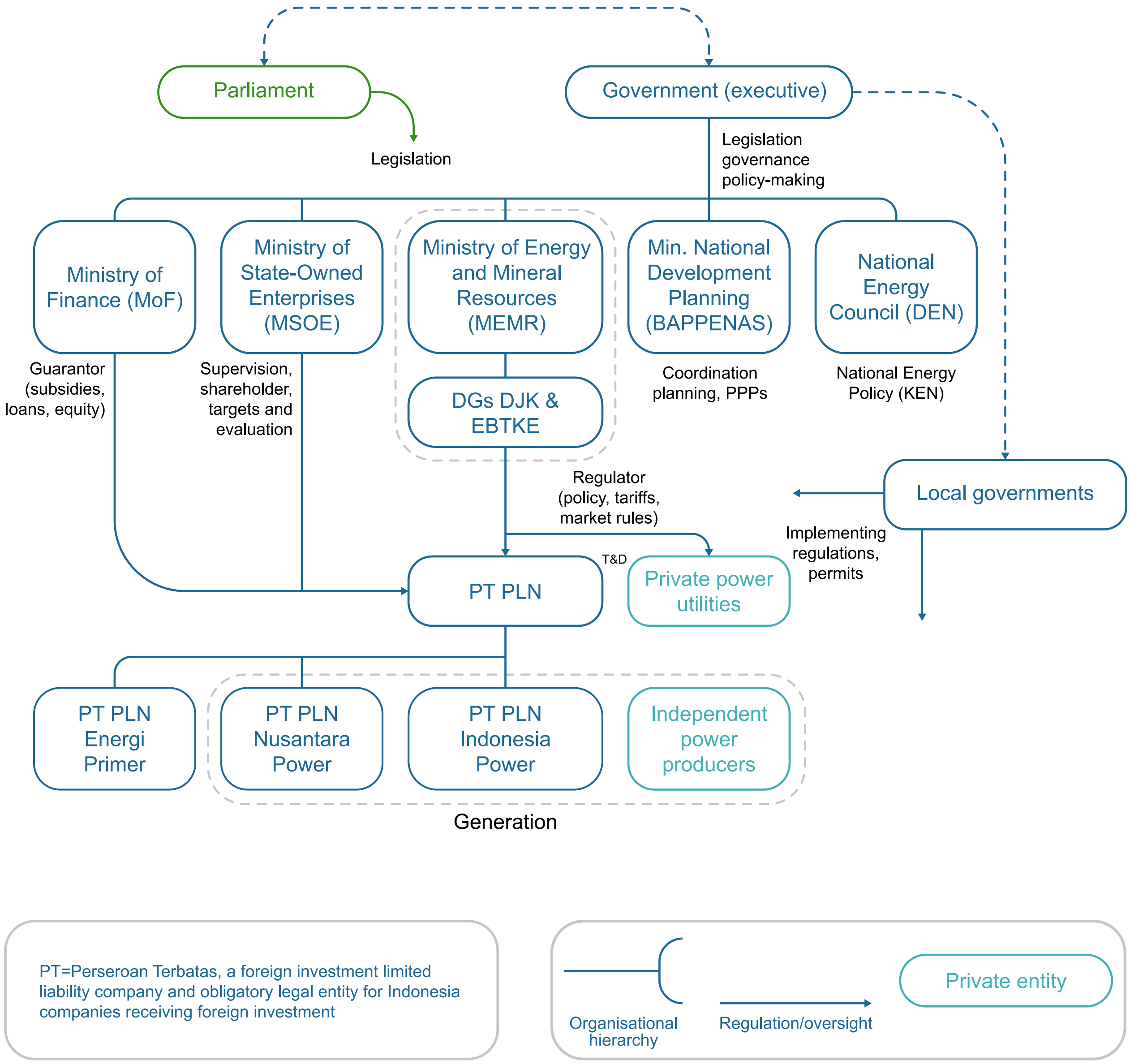
The Indonesian government opened the generation sector up to private investors with the Electricity Law of 1985, which it subsequently implemented through the Private Power Decree in 1992. This marked the transition to a monopsony in power generation, with PLN acting as the sole off taker of electricity. Corporatisation of PLN followed in 1994, transforming it from a public utility (perusahaan umum) to a public company (perseroan terbatas, PT), a process that was accompanied by functional unbundling (Sari, 2001).  Domestic reformers and multilateral development banks (MDBs) encouraged structural market reforms at the time. The pressure to implement these increased during the Asian Financial Crisis because it greatly affected Indonesia's economy and PLN's ability to meet payment and (foreign currency-denominated) debt obligations. The Electricity Law of 2002 cleared the way for the introduction of market competition in the generation and retail segments, the transition of PLN to a TSO/DSO utility and institutional reforms such as the establishment of an independent regulator. However, the law attracted opposition from diverse stakeholder groups – from those with vested interests in the sector seeking to protect existing arrangements to consumer groups fearing tariff increases and suspecting collusion in the privatisation of PLN's assets (Jarvis, 2012). The law was repealed in 2004 by the newly established Constitutional Court of Indonesia (MKRI). The court ruled against the law on the grounds that electricity production is a public commodity and must be under the control of the state, as per Article 33 of the Constitution (MKRI, 2003).

The succeeding Electricity Law of 2009 reaffirmed that PLN was to remain vertically integrated. It also introduced a permit system for the supply and distribution of electricity with priority rights for PLN, allowing it to retain its position as single offtaker. In 2016, two PLN labour union representatives successfully challenged certain provisions of the 2009 Electricity Law. They accused the provisions of being equivocal about Indonesia's electricity market structure and PLN's role therein, leaving a door open to future unbundling. The court ruled that the respective articles were conditionally unconstitutional and upheld the sector's vertically integrated status and the limited role of the private sector (Assegaf & Satwika, 2016). These constitutional interpretations have set boundaries on the scope for reforming the electricity market design in Indonesia.

Such boundaries need not constrain renewables deployment. State ownership, state assurances for private investors and fiscal support measures have underpinned Indonesia's market design and proved crucial when it comes to de-risking power sector investments. With targeted regulatory and contractual reforms, this model could be replicated for a fast-tracked renewables buildout. Accounting for a share of less than one percent of the supply mix, investment in variable renewables must increase considerably over the coming years.

## Institutional structure

**Figure 2. › Institutions and governance of Indonesia's electricity sector**



Multiple institutions across the tiers of government regulate and administer Indonesia's electricity sector. The People's Consultative Assembly, a bi-cameral parliament comprising the DPR (lower house) and DPD (upper house), and the central government are mandated to introduce energy sector legislation. These must pass the lower house with a majority vote to be enacted (DPR, 2023). Headed by the president, the executive arm of the government bears responsibility for implementing energy and electricity laws through regulations and policies. Local governments, whose jurisdiction was expanded under Indonesia's decentralised governance structure that became effective in 2001, support and oversee infrastructure development with fiscal incentives, subsidies, feed-in tariffs and permitting. However, these competencies have not been fully devolved and overlap with those of the central government.

Line ministries of the central government assume different areas of authority in regulating PLN and, more broadly, the electricity sector. The Ministry of Energy and Mineral Resources (MEMR) has a dual policy-making and regulatory role. It regulates the electricity sector with two directorates: the Directorate General of Electricity (DJK) and the Directorate General of New Renewable Energy and Energy Conservation (EBTKE). While DJK has a broader oversight role, EBTKE is responsible for developing renewable energy policies. Furthermore, MEMR is responsible for the (cross-sectoral) National Energy Policy (KEN).

The Ministry of State-owned Enterprises (MSOE) oversees the corporate management of PLN. It sets key performance indicators and appoints PLN's Board of Commissioners, which includes representatives of several line ministries. The Ministry of Finance (MoF) acts as PLN's guarantor. It compensates PLN with a subsidy to offset the utility's cost-recovery gap and provides concessional loans. It also supports public-private partnerships (PPPs) and IPP projects with equity and state guarantees. In line with this mandate, the MoF oversees PLN's investment plans. The Ministry of National Development Planning (BAPPENAS) establishes Indonesia's (cross-sectoral) medium- and long-term national development plans which, among other things, allocate the public budget to line ministries and state agencies and set the country's direction in line with the president's vision and priorities. BAPPENAS performs a coordinating role among the different ministries and ensures that electricity sector regulations and policies are integrated into the government's planning horizon. It also facilitates PPPs for infrastructure development.

Beyond these line ministries, several other government organisations assume an indirect regulatory or oversight role in the electricity sector. The National Energy Council (DEN) coordinates the implementation of the National Energy Policy among the line ministries and sub-national governments. It is headed by the president and vice-president of Indonesia and chaired by the minister of MEMR. Despite this, the DEN has not fully delivered on its mandate as the main coordinating body for Indonesia's energy policy. Other involved institutions include the Ministry of Environment and Forestry (environmental issues and permits), the Investment Coordinating Board (business permits), the Ministry of Industry (local content requirements) and the President's Staff Office (monitoring government programmes).

Overlapping mandates – vertically among different tiers of government and horizontally between ministries or coordinating government bodies – increase the complexity of decision-making and have rendered some institutions, like the DEN, less effective (OECD, 2021). At the same time, key electricity sector regulations, such as cost subsidies and tariffs, require parliamentary approval and are therefore subject to political interests. The automatic tariff adjustment mechanism introduced in 2014 smoothened this process to a certain extent. Greater regulatory autonomy could reduce political intervention and improve the regulatory framework for renewables, the opportunities for which the Asian Development Bank has assessed in a previous study (ADB, 2020).

## Market structure

Following the restructuring process in 2022, PT PLN now consists of the following four sub-holdings:

- PT PLN Energi Primer (PT PLN EPI): Upstream fuel procurement and production
- PT PLN Nusantara Power (PT PLN NP): Generation Company 1, previously PLN PJB
- PT PLN Indonesia Power (PT PLN IP): Generation Company 2
- PT PLN ICON Plus: Non-electricity sector business development, electronics and IT

The transmission and distribution networks are managed and operated by PT PLN Holding. PT PLN NP and PT PLN IP both provide operation and maintenance (O&M) and engineering, procurement and construction (EPC) services (including network maintenance) in addition to the production of electricity. PLN NP's assets span the entire country but are concentrated in Sumatra, Java and Bali. PLN IP has a significantly smaller asset base spread across Banten, Java and Bali.

The share of electricity from independent power producers (IPPs) has risen steadily over the years and reached 40 percent in 2022, with PLN still producing 60 percent of electric output (PLN, 2023a). The share of electricity PLN purchases from IPPs is expected to increase further over the coming years: PLN's Electricity Supply Business Plan (RUPTL) for 2021-2030 foresees 65 percent of new generation capacity over that period being developed by independent producers (OECD, 2021).

**Box 1. › Indonesia's renewable energy planning and targets**

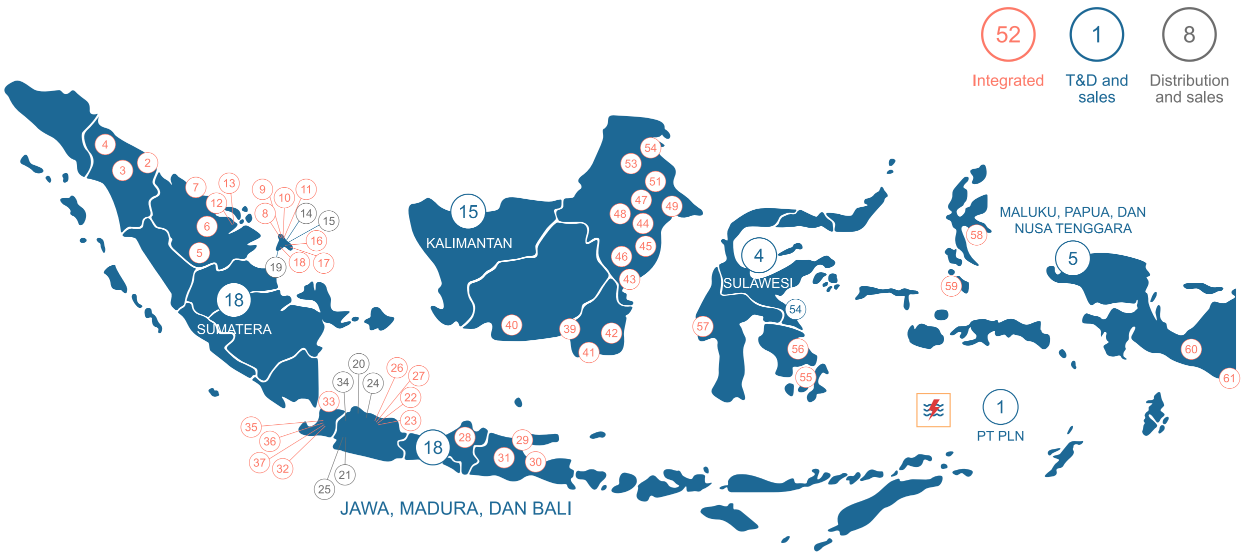
The RUPTL 2021 reduced planned additions to fossil baseload capacity and increased the pipeline of renewable capacity to 51.6 percent (20.9 gigawatts, GW) of total capacity additions towards 2030. Over 10 GW of hydropower is to be added over that timeframe, followed by solar energy (4.6 GW), geothermal (3.4 GW), wind and biomass (<1 GW). Drafts of the much-anticipated RUPTL 2024 indicate that PT PLN's Accelerated Renewable Energy scenario is to become the main planning scenario. This would raise the share of renewables to 75 percent of new capacity towards 2040, with gas plants accounting for the remaining 25 percent. If adopted as planned, approximately 28 GW in variable renewables and ~31 GW in dispatchable renewables are to be deployed towards 2040. The ambitious planning scenario would turn the tide of Indonesia's sluggish variable renewable energy uptake to date and support the country in reaching net-zero emissions by 2060. In 2022, dispatchable renewables delivered 13 percent and variable renewables delivered less than one percent of total eletricity production. The government of Indonesia had targeted a 23 percent share of renewable energy in the primary energy supply by 2025. As this target is unlikely to be achieved, the government is revising it as of 2024 and considering scaling it down.

Source: Ashurst 2021; PLN 2024.

In 2022, PLN served 85 million customers across the country at an electrification rate of > 99.5 percent (PLN 2023b). Indonesia's power sector comprises seven island systems: Sumatra, Kalimantan, Java-Bali, Sulawesi, Nusa Tenggara, Maluku and Papua. Each system has its own grid code, demand profile, generation portfolio and renewables potential. All the systems operate at 50.00 hertz (Hz) (±0.20 Hz) and are managed by PLN. The Java-Bali system is the largest in terms of network development, generation asset buildout and electricity demand, followed by Sumatra. Besides the main electricity networks, Indonesia has approximately 600 isolated small-island systems.

In line with the Electricity Law of 2009, PLN has priority rights for obtaining permits for the supply and distribution of electricity. Private power utilities (PPUs) serve areas stretching beyond PLN's network. In 2023, Indonesia had 61 business areas or Wilayah Usaha, the first one being PLN, which covered the entire country and represented 82 percent of installed generation capacity (69 GW) – including subcontracted assets from IPPs (Figure 3). The 60 PPUs are scattered across Indonesia's island systems and differ significantly in size – from 0.21 MW to 2.26 GW. Some PPUs serve load in isolated, off-grid areas while others are connected to PLN's network. Generally, they can obtain two types of permits. An Electricity Supply Business Licence (IUPTLU) is reserved for utilities serving end consumers, while an Electricity Supply Business License for Captive Use (IUPTLS) is for on-site generation (e.g. industrial parks). Depending on the agreement and proximity to PLN's network, these permits may include the right to sell excess electricity to the national grid at predetermined rates.

**Figure 3. › Electricity supply business areas in Indonesia's power system**




### 2-61: Private Power Utility (PPU)

1. PT PLN (Persero) (69 GW) ~ 82%
2. PT Perkebunan Nusantara III (9,4 MW)
3. PT Nadika Listrik Mandiri
4. PT Dwi Maharani
5. PT Mabar Elektrindo
6. PD Tuah Sekata (0,21 MW)
7. PT Riau Perkasa Energi
8. PT PLN Batam (658 MW)
9. PT Badamindo Investment Cakrawala (122,2 MV)
10. PT Tunas Energi (14,6 MW)
11. PT Panbil Utilitas Sentosa (39,9 MW)
12. PT Soma Daya Utama
13. PT Karimun Power Plant
14. PT Bintan Resort Cakrawala
15. PT Bintan inti Industrial Estate
16. PT Bintan Alumina Indonesia (150 MW)
17. PT Parama Multisarana Orion
18. PT Batamindo Solar Perkasa
19. PT Taman Resor internet
20. PT Energi Pelabuhan Indonesia
21. PT Tatajabar Sejahtera
22. PT DSS - Karawang 1 Mill (43,1 MW)
23. PT DSS - Karawang 2 Mill (95,2 MW)
24. PT Tegar Primajaya
25. PT Cibinong Center industrial Estate
26. PT Bekasi Power (134MW)
27. PT Cikarang Listrindo (1.156 MW)
28. PT United Power
29. PT Berkah Kawasan Manyar Sejahtera (24,5 MW)
30. PT Lamong Energi Indonesia (6,7 MW)
31. PT Pupuk Indonesia Utiltas (22 MW)
32. PT DSS - Sarang Mill (192 MW)
33. PT DSS - Tangerang Mill (20 MW)
34. PT Sumber Tenaga Lestari
35. PT Merak Energi Indonesia (120 MW)
36. PT Krakatau Posco (218 MW)
37. PT Krakatau Daya Listrik (120 MW)
38. PT Mikro Kisi Sumba (0,49 MW)
39. PT Energi Prima Nusantara (36 MW)
40. PT Surya Borneo Industri (15 MW)
41. PT Wijaya Triutam Plywood Industri
42. PT Makmur Sejahtera Wisesa (60 MW)
43. PT Kariangau Power (30 MW)
44. PT Bakrie Power
45. PT Kaltim Daya Mandiri (35,2 MW)
46. PT Kalimantan Powerindo (15 MW)
47. PT Indo Pusaka Berau (21 MW)
48. PT Sinang Puri Energi (0,4 MW)
49. PT Teluk Sumbang Energi (0,5 MW)
50. PT Long Beliu Tau Energi (0,6 MW)
51. PT Kayan Hydro Energi
52. PT Sumber Alam Sekurau (37,5 MW)
53. PT Kalimantan Energi Lestari Indonesia
54. PT Indonesia Morowali Industrial Park (2.828 MW)
55. PT Sultra Energi Indonesia
56. PT Konawe Cahaya Indonesia
57. PT Karampuang Multi Daya (o,6 MW)
58. PT Weda Bay Energi (2.260 MW)
59. PT Obi Sinar Timur (908 MW)
60. PT Biogreen Power Jayapura
61. PT Puncak Jaya Power (389,7 MW)

Though inter-island connections are only to be found in Java-Bali, the Indonesian government has committed to developing an integrated inter-island grid system to connect resource-rich areas to demand centres, unlock renewables potential, mobilise investment in remote regions and enhance the security of supply (Kontan, 2023). The Indonesian 'super grid', as it is dubbed, would require around 158 GW of high voltage transmission lines to be constructed towards 2050 at an estimated cost of 100-150 billion US dollars (IESR et al., 2021). An integrated power system could effectively support a fast renewables rollout in Indonesia. Under current plans, however, not all envisaged lines would support Indonesia's transition to a low-carbon generation mix. For example, the government has been mulling a high-voltage direct-current (HVDC) transmission project since 2014 that would connect new mine-mouth coal plants in Sumatra to demand centres in Java (KPPIP, 2023). With limited financial capital, new network investments should enable greater renewables deployment. In the Java-Bali system, the elongated and low-density nature of the transmission network will need upgrading and reinforcement to accommodate greater shares of variable renewables in the coming decade and beyond.

Indonesia's power system has faced structural overcapacity in recent years due to optimistic demand forecasts and insufficient incentives for cost optimisation. Electricity demand grew by seven percent per annum in pre-Covid years, collapsed in 2020 and then continued to grow at a lower rate. Nonetheless, system planners have consistently overestimated both peak and annual demand (IEA 2022). Generation capacity planning is centralised and implemented top-down through consecutive policy and planning documents.

- **The National Energy Policy (KEN):** A cross-sectoral national energy strategy for energy independence and security (GR 79/2014). It sets primary energy targets and requires approval by the House of Representatives (DPR) – Inonesia's lower and more influential house of parliament.
- **The National Electricity Master Plan (RUKN):** A 20-year electricity supply and demand outlook that identifies investment needs informed by the KEN. It is developed by the Ministry of Energy and Mineral Resources (MEMR), updated at least every three years and subject to consultation with the lower house – the DPR). The RUKN encompasses electricity generation, transmission and distribution.
- **The Regional Electricity Plan (RUKD)** guides subnational sectoral planning based on the RUKN and is to be developed by regional governments within one year of the RUKN's launch.
- **The Electricity Supply Business Plan (RUPTL):** A ten-year business plan outlining investment requirements in the electricity generation, transmission and distribution segments that is reviewed annually. The business plan comprises demand and production forecasts, system expansion plans and expected fuel requirements, among other things. All business licence holders (utilities) are obliged to issue annually updated RUPTLs for their operating areas so that they can be endorsed by MEMR. The RUPTL, particularly PLN's, is the leading document for electricity sector investments and determines the future technology mix as well as the market share of IPPs.

The RUPTL has been criticised for its lack of transparency and for failing to deliver investment efficiency. Stakeholder consultations are reported to be minimal, fuel-source targets of the RUPTL and RUKN appear to be misaligned and nondisclosure of key factors such as reliability targets and the location of new capacity are reportedly hampering external assessments of grid requirements (ADB, 2020). In recent years, the RUKN's and RUPTL's demand forecasts have proven overly optimistic, resulting in overbuilding of capacity and higher system costs. Indonesia has a planning reserve margin (PRM) target of 35 percent, well above international standards in the 10–20% range. The actual reserve margin in the Java-Bali system was 50 percent in 2023, which PLN forecasts will dip below 35 percent by 2029. Indonesia's significant reserve capacity (in coal power) imposes a structural constraint on the deployment of renewables. Under current conditions, VRE additions would decrease the capacity factors of coal plants receiving capacity payments and result in increased system costs overall – we return to this issue in this chapter's section "Market and contractual arrangements". Consequently, PLN is not planning to ramp up renewables before 2030 (PLN, 2023).

The oversupplied market underscores the urgency of an accelerated coal phase-out to clear the way for the sector's transition towards renewables. The Joint Energy Transition Partnership (JETP) aims to address this with blended public-private finance, targeting low-carbon investment and early retirement of coal plants. However, experts and stakeholders have expressed concern about the speed of implementation and scale of the coal retirement programme; a mere 2.5 percent of the 97 billion US dollars in investments needed to achieve JETP targets is earmarked for early retirement and coal plant retrofits, with network development and energy efficiency being given greater priority (JETP, 2023). The Asian Development Bank's early retirement programme for coal plants, the Energy Transition Mechanism, is being put to work in Indonesia and subsumed under the JETP financing. The early retirement of the 660 MW coal plant Cirebon-1 serves as the mechanism's pilot project.

At a more fundamental level, new incentives and procedures are needed to encourage cost optimisation in the planning process.

- **Technical:** There is a need to gradually lower the PRM target of 35 percent while adopting additional reliability metrics such as loss of load expectation (LOLE), loss of load probability (LOLP) and expected energy not served (EENS). These metrics allow for probabilistic assessments that can better anticipate and prevent contingencies as the share of VRE increases (IEA, 2022a).
- **Governance:** Stakeholder consultations on the energy master plans and RUPTLs could be institutionalised to increase the accuracy and robustness of modelling forecasts and their underlying assumptions.
- **Regulatory:** Under the cost-plus margin framework, PLN passes on the costs of new assets to rate- or taxpayers and sees its regulated asset base and revenue increase, irrespective of actual demand. Performance-based regulations can incentivise it to increase returns through cost savings in the absence of market reforms (Aas, 2016).
- **Market:** Current policies and contracts favour fossil over renewable energy. A level playing field in the market and system operations is a requirement for Indonesia to firmly shift away from coal towards renewables in procurement and dispatch decisions. Reforms should target fuel-cost (coal) subsidies, dispatch distortions and risk-return allocations in thermal and renewable PPAs. We return to these aspects in the sections “Policy instruments for VREs” and “Market and contractual arrangements”.

## Investment regulations and market openness

Indonesia's investment environment has become increasingly open to foreign investors over the years. It is anticipated that more than half of investments in renewables towards 2025 will come from foreign sources, with international investors expected to contribute over 60 percent of new capacity in geothermal, wind and solar energy (PwC, 2023). Foreign companies are required to establish a local subsidiary (Perusahaan Penanaman Modal Asing) to do business in Indonesia. The government applies foreign shareholding ceilings that range from 49 to 95 percent (PwC, 2017). Consequently, foreign companies must establish a joint venture with an Indonesian company. The government's Negative Investment List details the extent to which foreign direct investment is allowed in a particular sector or business activity. For the electricity sector, two limitations apply: foreign direct investment is ruled out for plants with a capacity of <1 MW, while for small power plants of 1-10 MW the 49 percent foreign ownership ceiling applies (PwC, 2023b).

PLN is responsible for grid maintenance and upgrades. Private sector participation in network investments has so far been limited to selected cases where an IPP was required to invest in the connection between its plant and the grid. Faced with financial constraints, PLN indicated in its 2019 and 2021 RUPTLs that it might put new transmission lines out to tender. Build-operate-transfer (BOT), build-lease-transfer (BLT) and power wheeling schemes are under consideration, yet no such tender has been launched to date.

### Third-party access

MEMR regulation no. 11/2021 provides a framework for introducing transmission tariffs and encourages (though does not oblige) PLN and PPUs to provide network access to third parties. A third-party grid access (TPA) regime could boost Indonesia's renewable energy deployment by enabling private producers and large consumers to conclude bilateral contracts for the supply of electricity while compensating PLN for network usage. Demand for private RE PPAs is increasing as companies seek to procure low-carbon energy. At the same time, investors stand to benefit from reduced lead times, particularly in contract negotiation, and from greater flexibility in meeting demand beyond what is envisaged to be procured in (centralised) tender rounds. A third-party access regime introduces a degree of (decentral) competition into the system, enabling large electricity consumers to procure renewable energy from offsite locations and support the construction of new capacity. Open network access would alter PLN's position as the sole offtaker of electricity and, until recently, was not on the policy horizon. As of 2024, the government of Indonesia is considering introducing a power wheeling scheme as part of the upcoming New Energy and Renewable Energy Bill. This could help it attract more investments in the nascent renewable energy market.

### Local content requirements

Local content requirements for solar PV have restricted market openness in the upstream renewable industry. The Indonesian government introduced local content requirements (LCRs) for solar PV in 2012 with a view to promoting a domestic industrial base and supporting job growth. Consecutive amendments in 2017 and 2022 sought to increase the LCRs for the solar PV modules to 60 percent. An additional regulation (MoI 23/2023) postponed this target to 2025 and established a 40 percent LCR target for the interim period. Following domestic supply bottlenecks and financing challenges, new regulations introduced in 2024 reduce the LCR target for solar power projects to 20 percent and exempt projects that have at least 50 percent of their finance provided by foreign investors. The eased rules apply to projects that have a PPA signed before the end of 2024 and that will be operational before the second half of 2026 (Jowett 2024).

LCRs can support a nascent domestic industry base if they provide targeted incentives for manufacturers to become internationally competitive and if they are introduced in a growing renewable energy market that ensures demand. If not sufficiently embedded in a broader industrial strategy, however, LCRs risk driving up costs and delaying the deployment of renewables. Furthermore, LCRs are susceptible to international disputes and have been ruled incompatible with international trade law in cases against Canada, the US and India (Boute, 2023).

Indonesia's local content measures have two drawbacks – their timing and their strategy. LCRs were introduced at a time when the domestic market for solar power had not yet taken off and renewable support policies were inadequate to mobilise sizeable investments. This has hindered economies of scale and efficiency improvements in manufacturing. At the same time, there have been insufficient incentives and support measures for the nascent industry to become internationally competitive (Derbyshire et al., 2021). Solar PV modules of Indonesian origin – TKDN PV modules – are less efficient and more costly than Tier-1

PV modules. Under the tariff policy of 2022 (PR No.112), developers using TKDN modules can achieve an internal rate of return (IRR) of 14 percent at the RE ceiling price, compared to over 20 percent for those using Tier-1 modules, according to a calculation by IESR (2023). So far, Indonesia's LCRs have added a cost premium which reduces the competitiveness of solar PV versus other technologies and affects the bankability of projects. Several studies have proposed reforms of the policy, including targeted exemptions of LCRs, phasing LCRs, interest subsidies for manufacturers, joint ventures between international and local producers to encourage technology spillovers, public support of R&D and a stable RE project pipeline to achieve scale and enable upstream investment (Derbyshire et al., 2021; JETP, 2023). Though the regulations introduced in 2024 temporarily assuage the constraints imposed by the LCR regime, they must be complemented with structural reforms of Indonesia's trade policy and low-carbon industrial strategy.

## Policy instruments for VREs

Renewables deliver about 12 percent of Indonesia's total power supply, while VREs account for less than one percent. According to current targets, the share of renewables must reach 23 percent by 2025. As this share is unlikely to be reached, the government is considering lowering the renewables target to 17-19 percent, signalling the need for adjustments to the policy framework in order to scale the deployment of clean technologies.

Until 2022, electricity tariffs for renewable energies were capped at 85 percent of the local average costs of electricity generation (the BPP)[1]. As a consequence, VREs had to outcompete subsidised coal plants by a significant margin which – in combination with LCRs – undermined the bankability of new projects. Presidential Regulation (PR) No. 112/2022 on Accelerating Development of Renewable Power Supply aims to correct that distortion with a new ceiling tariff based on 1) technology type, 2) the location of the generation asset and 3) its size. The new tariff is phased, with a higher ceiling during the first ten years that gradually declines thereafter until the end of the PPA to allow for faster debt repayment and lower capital costs. DJK, in coordination with the MoF and MSOE, compares the ceiling tariffs annually to PLN's latest contract prices and may amend them by ministerial regulation. Although the tariff design constitutes a significant improvement on its predecessor, the underlying principle that the cost of renewable energy projects must not surpass the average cost of electricity generation remains. As such, PR 112/2022 caps feed-in tariffs for renewables at 100 percent of the BPP.

PR 112/2022 leaves out detailed PPA terms which MEMR develops in a separate regulation. We discuss the implications of the new (draft) RE PPA regulation in the section "Market and contractual arrangements" under the heading "Market integration of VREs".

The tariff for a renewable energy project is negotiated with PLN and follows a tendering procedure largely based on the previous regulation (MEMR 50/2017). PLN uses two procurement routes: 1) direct selection and 2) direct appointment. The direct selection scheme is the main procurement route for variable renewables. It involves a two-step tender process with a pre-selection round based on technical and financial criteria, followed by competitive selection in the form of a capacity auction. The direct appointment scheme concerns projects where a PLN subsidiary has a majority

1 The BPP, or average costs of electricity, comprise power purchases and generator rentals, operation, maintenance and fuel costs, personnel costs, administration costs, depreciation on operational fixed assets, and interest and other financial costs of the supply of electricity (ADB 2023).

share and takes responsibility for partner selection. It is mostly used for dispatchable renewables (geothermal, hydropower). Stakeholders indicate that the PPAs resulting from the tendering and negotiation process are bankable but point to several bottlenecks to be addressed to ensure a cost-effective and scalable renewable energy procurement pipeline.

- ► **Long-term clarity on renewable energy procurement:** The pace and frequency of tenders should increase given investor readiness to grow the renewable energy market. The tendered capacity volumes could also increase in order to unlock economies of scale.
- ► **Shareholder arrangement (direct selection):** Under the direct selection route, IPPs are obliged to partner with a PLN subsidiary, which assumes a 30-35 percent equity share in the form of a shareholder loan (i.e. without providing capital upfront). Under this arrangement, risk allocation is skewed towards the IPP, as PLN does not provide upfront financing or project development support. This affects the bankability of renewable energy projects.
- ► **Distorted bidding and selection (direct selection):** Since the electricity tariff for a project is negotiated with PLN, project developers face an incentive to bid with overly optimistic cost assumptions to be selected and enter into the negotiation phase. In parallel, some sunk costs, such as land acquisition, are not adequately considered in the selection process even though they render the successful implementation of a project more likely.
- ► **Shareholder arrangement (direct appointment):** In the joint control scheme, PLN assumes a majority share in the project while providing ten percent of the capital investment. This requires an additional investor, or sponsor, to cover the capital investment of PLN's remaining 41 percent share (Hoed, 2018). Furthermore, lenders might be less willing to finance an IPP without a majority stake in the project. As a consequence, this procurement route faces significant drawbacks.
- ► **Transaction costs:** The contract negotiation process may add between six to nine months to the lead time of a renewable energy project, thereby significantly increasing transaction costs. The initial terms of a PPA tend to allocate risk to the project developer, including liability for transmission constraints (up to 100km in proximity), foreign exchange risk and force majeure clauses.

**RECOMMENDATION – enhance the VRE procurement process.** The procurement and negotiation processes for reaching a PPA that investors are willing to back require optimisation and fewer hurdles. Quick gains for a cost-effective pipeline of renewable energy projects include the introduction of a standard RE PPA that conforms to international best practices (see section "Market and contractual arrangements"), government support in siting, land acquisition and impact assessments, and the introduction of a scoring system to increase the transparency of the selection process. The RE ceiling tariff should be disconnected from the average cost of electricity generation to level the playing field for investment. Beyond these measures, renewable energy procurement must be scaled up for Indonesia to reach its RE target of 23 percent by 2025 and higher shares thereafter.

***Renewable energy certification***

PLN introduced renewable energy certificates (RECs) in 2020, allowing consumers to claim the use of renewable energy on a MWh basis (PLN, 2021). RECs are issued from PLN's own geothermal and hydropower assets and the proceeds are held in a special account to finance RE sources. PLN holds RECs from IPP projects in a separate account. Since RECs are not included in PPAs and IPPs do not have access to them, the scheme does not provide any incentive for renewable energy deployment beyond PLN's intended revenue allocation.

### Distributed energy resources (DERs)

Indonesia is aiming to achieve 3.6 GW in rooftop solar by 2025. By the end of 2023, installed capacity in solar power totalled 574 MW, of which about 90 MW was in rooftop solar (ESDM, 2024). The meanwhile superseded MEMR Regulation No. 26/2021 introduced two major incentives to accelerate the deployment of rooftop solar power in Indonesia: 1) net metering; previously, net billing was used, with excess electricity from rooftop solar being sold at a 35 percent discount, and 2) full self-consumption, with a capacity limit set at 100 percent of contracted load. By contrast, the same regulation discouraged rooftop solar for industries by imposing a monthly capacity charge (ESDM 26/2021). In 2022, PLN responded to the self-consumption measure with a "15 percent rule" that capped installed capacity at 15 percent of the contracted load. This undermined the strengths of Regulation 26/2021 and inhibited the growth potential for rooftop solar power in the country.

The incentives for investment in behind-the-meter solutions shifted once more with the introduction of **MEMR Regulation No. 2/2024**. The new regulation paves the way for solar PV deployment by industrial consumers but discourages solar uptake in households.

► **A quota system replaces the capacity limitations. Investors in rooftop solar will need to acquire a permit from the IUPTL holder (i.e. PLN or the respective PPU) and face sanctions in case of non-compliance.** Quotas for new DER capacity are to be issued for five-year periods and must consider the National Energy Policy, RUPTLs and system reliability aspects. At worst, the quota system could have the effect of a new market cap on DER in Indonesia. However, if aligned with the government's capacity targets (as foreseen) and issued in full (uncertain), the quotas could serve as a tool for tracking and expediting DER growth.

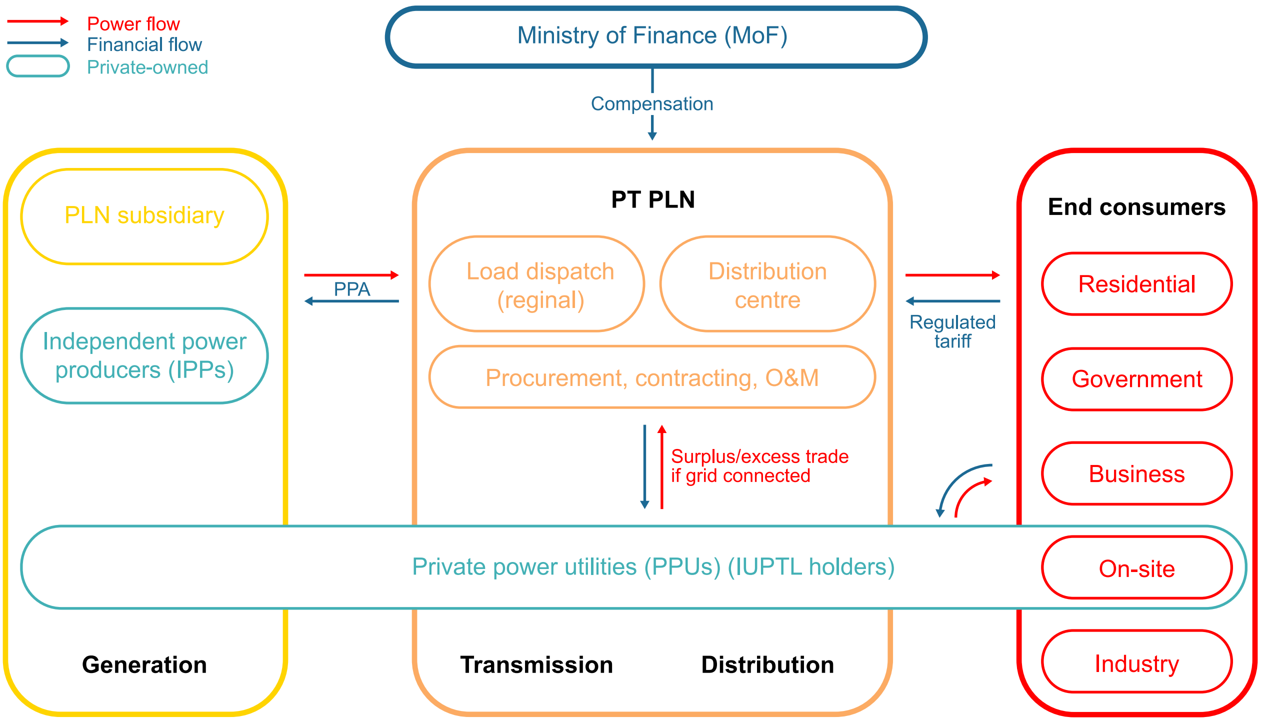
► **Annulment of net metering – with zero compensation for excess electricity fed into the grid (100 percent discount)** Net metering for rooftop solar power is a critical incentive for residential consumers due to the mismatch between peak generation (afternoon hours) and peak demand (evening hours). It supports households with intertemporal flexibility in recouping their investment costs. Without it, households wanting to invest in DER could consider storage solutions to match their load and generation profiles, yet adding battery storage would increase the upfront investment costs to a level that would make them unaffordable for many Indonesians. To avoid a continued lapse in residential DER deployment, the revocation of net metering could be complemented by household investment support schemes such as concessional loans and grants or third-party ownership models. A net-billing scheme could also be considered.

► **Removal of monthly capacity charge for industrial consumers**Industrial consumers are less affected by the discontinuation of net metering as they can maximise electricity consumption during the day, i.e. during peak generation hours. In line with the focus on self-consumption, the removal of the capacity charge eliminates an operational cost for this consumer group and is slated to increase the return on investment of rooftop solar projects. This is a positive development in light of corporate demand for clean power and industries' access to finance. With vast resource potential, distributed solar energy can deliver a substantial contribution to Indonesia's power system transition pathway.

## Market and contractual arrangements

In Indonesia's integrated IPP model, power generation is separated from integrated mid- and downstream activities (transmission, distribution, retail). IPPs, often in partnership with a PLN subsidiary (GenCo), conclude power purchase agreements with PT PLN – its IPP procurement divisions and corporate legal sub-directorate. PT PLN also concludes contracts with its subsidiaries' power plants. Contrary to IPP arrangements, PLN's internal PPAs are not strictly based on commercial terms (ADB, 2023). Furthermore, IPPs can enter into agreements with private power utilities in areas beyond PLN's. This is less common given PPUs' integrated operations, smaller (area) size and demand load. Overall, competition in the sector is limited to the energy procurement phase.

**Figure 4. › Indonesia's long-term contract market with regulated entry of private players**




PT PLN runs regional load dispatch centres for each of its main transmission networks, while PLN's distribution control centres balance the local networks and deliver power to end consumers. PT PLN dispatches generators at 10:00 AM for the following day according to their submitted schedules and marginal cost. VRE plants submit real-time generation data and daily forecasts at 15-minute intervals that are updated every six hours. Operators of hydropower plants must update the system operator every hour about reservoir levels and provide production forecasts for the following day. The day-ahead dispatch schedule constitutes the final operational plan and follows annual, monthly and weekly system operation planning horizons. PLN does not currently use an intraday unit commitment ahead of real-time balancing. Doing so would support the least-cost integration of variable supply by reducing the need for balancing from reserves as dispatch schedules would be updated closer to real-time (IEA, 2022a).

### Retail electricity tariffs

In 2023, electricity tariffs ranged from 997 to 1 700 Indonesian rupiah (IDR) per kilowatt-hour (kWh), equivalent to USD 0.066/kWh to USD 0.112/kWh1. Tariffs in Indonesia are differentiated by consumer group (Figure 4) and connected capacity (volt-ampere). Single-rate tariffs apply to all residential groups, businesses below 200 kilo-volt-ampere (kVA) and public buildings below 200 kVA. Time-of-use tariffs apply to businesses and public buildings above 200 kVA and to industry. These large consumers are also subject to a peak load charge when drawing more than 85 percent of their connected power from the grid. MEMR introduced an automatic tariff adjustment mechanism in 2014 that was amended several times in subsequent years. The mechanism allows PLN to revise its tariffs every quarter and pass on changes in capital and operational costs, such as increases in inflation, fuel costs and exchange rate-related costs. However, MEMR frequently freezes tariff adjustments to keep prices low. This happened in 2018, 2019, 2023 and 2024. On a larger timescale, the government has managed to gradually increase the average electricity tariff to improve PLN's cost recovery. As a result, tariff subsidies almost halved between 2012 and 2022, from IDR 103.3 trillion to IDR 58.8 trillion (PLN, 2023).

Despite these improvements, PLN remains reliant on cash injections from the Ministry of Finance. In 2022, its revenue shortfall amounted to IDR 67.5 trillion (USD 4.5 billion) (PLN, 2023). (PLN's revenues totalled IDR 311.1 trillion from electricity sales, IDR 0.9 trillion from connection fees and IDR 6.7 trillion from operational revenues, against a total operational cost of IDR 386.2 trillion). PLN receives two types of government payments to offset the shortfall: 1) subsidy payments that cover the cost difference of subsidised tariffs and 2) compensation payments that offset the below-cost-recovery tariffs of non-subsidised consumer groups – in response to tariff hike freezes. These totalled IDR 58.8 trillion (USD 4.0 billion) and IDR 63.6 trillion (USD 4.3 billion) respectively and allowed PLN to report an operating profit of IDR 54.9 trillion (USD 3.7 billion) for that year. This figure excludes interest/debt payments and taxes. The implications of this revenue model in terms of PLN being able to drive renewable energy deployment are discussed in further detail in the "PLN's business model" section below.

### Contractual arrangements

The private sector participates in electricity generation through IPP and PPP arrangements, the details of which are outlined in several regulations (MEMR 03/2015; GR 23/2014; PR 38/2015; PR 112/2022). Contracts for conventional power plants are awarded through a) direct appointment, b) direct selection and c) open tender. Since the introduction of PR 112/2022 on Accelerating the Development of Renewable Power Supply, the procurement of coal-fired power plants has been subject to a set of constraints: 1) the pipeline of new projects is limited to the capacity additions provided for in the RUPTL of 2021-2030. This is about 14 GW, or 34 percent of the total capacity additions towards 2030. Beyond that number, 2) new coal plants are allowed on the condition that their emissions are reduced by 35 percent within ten years of commercial operation – by means of retrofits or carbon offsets. 3) New and existing coal plants are allowed to operate until 2050 but not beyond. Restrictions on captive coal plants (i.e. on-site for industrial use) are looser: new capacity is allowed if its use contributes to job creation and economic growth. Yet, like on-grid coal assets, their operations must cease by 2050.

**Table 2. › PPAs for baseload assets in Indonesia contain five tariff components covering capital, fixed and variable costs**

| | |
|---|---|
| FIXED | |
| Component A | Capital recovery and return on capital based on the asset's capacity and a mutually agreed availability factor |
| Component E | Cost of capital recovery for IPP-built transmission line connecting its plant to the grid. (PLN assumes ownership, operation and maintenance upon completion of the line). |
| Component B | Fixed O&M cost irrespective of production – salaries, insurance, tax, spare parts etc. |
| VARIABLE | |
| Component C | Fuel cost – based on transferred energy (kWh) and the plant's combustion efficiency |
| Component D | Variable O&M cost |

Source: PLN 2017a.

Table 2 shows the tariff components of a power purchase agreement for coal power plants. Detailed aspects such as force majeure clauses, exchange rate risk and grid cost agreements are settled through bilateral negotiation. PPAs are typically signed for 20–30 years, during which time capital costs are recouped. The long-term contracts include capacity payments that cover the power plant's cost of capital (principal repayment, interest and return on equity), as well as fixed operation and maintenance costs. Capacity payments (components A, E and B in Table 2) constitute up to 40 percent of the total tariff. PLN subsidiaries typically receive a lower capacity payment than independent power producers, partly reflecting their lower financing costs. PT PLN disburses capacity payments irrespective of the actual power delivered but imposes a penalty if an IPP does not achieve its contractually agreed availability factor, typically 80-85 percent for coal plants (PLN, 2017).1 With the introduction of new PPA regulations in 2017 and 2018, this penalty became explicit and required an IPP to compensate PLN for the cost of substituting supply it did not deliver (deliver-or-pay) (PwC, 2023). Previously, the penalty had involved a commensurate reduction in the capacity payment paid out to an IPP.

On the back of the capacity payment structure, PLN has successfully attracted private-sector investment in electricity generation, effectively assuming producers' market risk. Furthermore, sovereign guarantees protect PLN in the case of default and mitigate the offtake risk faced by independent power producers. The capacity payment structure in PPAs drastically lowers the investment risk and ensures project bankability. It shields IPPs from unforeseen changes in dispatch decisions and, in the long term, from any stranded asset risk. In return, PLN is assured of sufficient capacity to meet demand. Despite the advantages of capacity payments for attracting investments and securing electricity supply, their use under the current system is at odds with a renewables-based transition. Over-procurement of coal power capacity has meant that excess capacity payments are locked into PLN's financial obligations, increasing the system cost of electricity and limiting the deployment potential of renewable energies. Designed for baseload availability, the PPAs lack the criteria for flexibility service provisions, the need for which increases with VRE deployment. The coal PPA structure needs to be revisited to ensure that renewable energies enter the power system at the least cost.

- **System costs:** IEEFA estimates that capacity payments to coal plants will total USD 3.16 billion per GW of installed capacity throughout a 25-year PPA (Chung, 2017). This becomes problematic in an oversupplied market – such as in the Java-Bali system, where the reserve margin is close to 50 percent. PLN could meet peak demand and maintain a 15 percent reserve margin with all combined assets and a thermal power fleet two-thirds of its current size (Prasetiyo et al., 2023). Keeping its excess (coal) generation capacity operational entails an annual bill of around IDR 16 trillion, or approximately USD 1.2 billion, in fixed O&M costs (Ibid). Payments to cover the excess capacity add at least another USD 2 billion annually. Capacity payments are inflation-indexed and increase accordingly. In Indonesia's subsidised tariff regime and cost compensation structure, these costs are ultimately borne by taxpayers. In a long-term contract market with high capacity-based payments like Indonesia's, deploying variable renewables may thus come at a higher total cost to the system in the interim since the utility is bound to make contractual payments to a fossil fuel fleet that is set to be outcompeted by new renewable energy assets.
- **System flexibility:** Ramp orders, frequency control, reactive power and other system services are subsumed under the availability factor and expected to be provided as such. While power plants are penalised if they fail to achieve their availability factor, PPAs for thermal power do not put an explicit price on flexibility service provisions such as ancillary services. Capacity payments could be reformed to value system flexibility services rather than baseload availability, thereby aligning them with emergent system needs as VREs are deployed.

**RECOMMENDATION – repurpose the coal fleet for flexibility services.** Although less flexible than mid-merit and peaking plants, Indonesia's coal fleet could support the integration of solar PV by lowering output during daytime hours and increasing production overnight where needed. More flexible operation of coal assets could increase the variable costs per unit of electricity due to lower fuel efficiency. However, coal plants' total variable costs would decrease with lower capacity factors, yielding fuel cost savings for the power system. By explicitly putting a price on the system services coal plants can provide, reformed PPAs with a flexibility component (ramp requirements, frequency control, re-active power, spinning reserve) would justify a shifting cost and operational profile of fossil fuel assets. The upshot would be that the sunk costs (capacity payments) for baseload power would be redeployed for system flexibility services to integrate variable renewables. This approach should target newer and more efficient coal assets. A ministerial regulation will be required before PLN can renegotiate its contracts with independent producers. Given the rigidity of existing PPAs, a contract renegotiation approach would need to be developed (see Nalule, Heffron and Olawuyi, 2023; Boute, 2021).

**Box 2. › Repurpose, reserve and retire: Foreign investment protection and coal exit pathways for Indonesia**

Approximately one third of Indonesia's grid-connected coal fleet is owned by investors from Japan, Korea and China. This share is expected to increase to about half of total coal power capacity by 2025 as new foreign-owned coal assets come online and older domestic ones are retired (Cui et al., 2023). Foreign-owned coal assets are protected under international investment law, allowing investors to challenge coal phase-out decisions and seek compensation. International arbitration provides an additional layer of (foreign) investor protection on top of what has been agreed in PPAs. This could jeopardise host states' regulatory powers to pursue an accelerated coal exit strategy (Boute and Hug, forthcoming). To circumvent protracted legal disputes, the government could prioritise the coal assets of PLN and domestic IPPs for early contract termination and settle potential compensation payments according to the national legal framework. Meanwhile, foreign-owned coal plants could play a transitionary role. They could be repurposed to provide flexibility to the power system while less efficient excess capacity could be placed in a long-term strategic reserve – reducing operation costs to a minimum and clearing the way for VREs to be deployed at greater speed.

**Box 3. › Contractual flexibility from Indonesia's gas-fired power fleet**

PLN has annual and monthly gas supply contracts with minimum and maximum offtake volumes. The fuel supply contracts include take-or-pay provisions, mainly to provide revenue certainty for investments in upstream infrastructure such as pipelines (IEA, 2022b). The take-or-pay provisions for fuel supply are backed up by commensurate minimum offtake requirements for gas-fired electricity, ensuring the procured gas volumes are consumed and their costs recovered. Since PLN procures gas annually and monthly, gas power plants can be operated flexibly on an intraday basis and accommodate daily fluctuations in variable renewable output when their share in the system increases. The fuel supply contracts do reduce the gas fleet's flexibility to adjust output volumes over longer timescales, however. To address this, the minimum gas offtake clauses in supply contracts could be reduced and more diversified fuel procurement strategies adopted, for instance by increasing the volume share of flexible short- and mid-term supply contracts. However, this is not an immediate priority. In 2022, gas-fired power plants delivered 18-19 percent of total electricity generation in Indonesia (PLN, 2023b; JETP, 2023). More flexible operation of the gas fleet will support the integration of variable electricity supply and may not require reductions in annual gas output volume over the mid-term. Indonesia's coal fleet will have to absorb decreases in thermal power output before the gas fleet is affected. This requires the true cost of coal to be adequately reflected in dispatch decisions.

## Fuel costs and carbon pricing

The Indonesian government subsidises coal consumption through its domestic market obligation (DMO) policy, which obligates coal producers to reserve a certain percentage of output for the internal market at a capped price. Since 2018, this percentage has been set at 25 percent, with prices capped at USD 70 per tonne for high-grade coal, USD 43 per tonne for medium-grade coal and USD 37 per tonne for low-grade coal (MEMR 23/2018; MEMR 1395/2018). In 2024, the DMO is to rise to 30 percent (220 Mt) to meet increased demand from the electricity (170-180 Mt) and industry sectors (Reyes & Jones, 2024).

The DMO has been an important market price support instrument for the government, allowing it to suppress the average cost of electricity generation (BPP) and maintain affordable electricity prices for consumers. It reduces compensation payments from the Ministry of Finance to PLN and thus the cost burden of subsidised electricity tariffs, thereby supporting the public budget. The DMO furthermore provides PLN with supply security, reduces its operational costs and shields it from exposure to volatile energy markets (since the price caps are indexed in US dollars, PLN is exposed to currency risk). In its current form, the DMO is a cross-subsidy that imposes an implicit product tax on the mining industry, reflected in a lower sale price and foregone revenue, which is used to suppress input costs for the electricity sector.

**While supporting the public budget, PLN and end consumers, the DMO distorts short- and long-term price signals in the electricity sector and tilts the playing field in favour of coal-fired power plants.**

- **Investment signal for coal:** Fuel costs constituted 60 percent of PLN's (fixed and variable) operation costs for its asset base in 2022 (PLN, 2023b). The DMO, further backed up by a temporary coal export ban, kept prices stable during that year of exceptionally high coal prices. In ensuring low fuel costs and insulating power producers from international market swings, the DMO has rendered coal plants in Indonesia a highly competitive generation source. This economic signal has informed planning and procurement processes and is an underlying driver of Indonesia's rapid coal asset buildout over the past decades.
- **Investment signal for renewables:** The DMO lowers the average cost of electricity generation (BPP), which sets the ceiling price for renewable energy tariffs. Consequently, variable renewables have to compete with subsidised coal plants.
- **Dispatch signal:** The DMO keeps coal plants' marginal costs low, ensuring their dispatch ahead of other generation sources. The price cap on coal will also limit the effectiveness of climate policy instruments that seek to induce merit order changes based on emissions intensity, such as Indonesia's cap-tax-and-trade carbon pricing policy.

**RECOMMENDATION – convert the domestic market obligation into a domestic tax obligation.**
The domestic market obligation could be converted into a technology-neutral price support measure to remove market distortions. This could take the form of an explicit product (windfall) tax on coal mining companies, as previously proposed by Bridle, Anissa and Mostafa (2019). We suggest transforming the domestic market obligation into a domestic tax obligation (DTO). A DTO would tax the share of coal that upstream companies sell domestically, generating tax revenue that could be used to support consumers without distorting price signals in the electricity value chain. Under the proposed DTO, the domestic supply obligation would remain but the domestic price cap would be converted into a strike price (e.g. USD 70/tonne), above which a product tax would apply. This would work as follows:

- Coal producers would sell a predetermined share of their output to the domestic market (supply obligation) at the prevailing international market price. As a result, IPPs and PLN might incur higher fuel costs than before – if the market price of coal were to exceed the domestic strike price (USD 70/tonne) – and reflect these in their business operations. This would correct investment and dispatch signals.

- The government would tax coal sold domestically at above the strike price. At a tax rate of 100 percent and a strike price of USD 70/tonne, coal sold at a market price of USD 100/tonne would yield USD 30/tonne in tax revenue. The government could adjust the tax rate to take account of coal price developments and subsidy requirements.
- The Ministry of Finance would administer the domestic coal product tax and use the proceeds to compensate PLN for higher fuel costs incurred (in the case of subsidised end-user tariffs) or consumers (in the case of cost-reflective tariffs).

Hence, the domestic tax obligation would ensure that the cost of coal is passed on from fuel suppliers to electricity producers, removing a significant market distortion that would otherwise disadvantage renewable energy technologies. If the international market price of coal were reflected in dispatch decisions, coal plants' marginal costs would increase, favouring the utilisation of cleaner supply sources. As a consequence, PLN would incur higher fuel costs that it would need to recover.  The tax revenue could be used for this purpose. The Ministry of Finance could compensate PLN so that electricity tariffs would remain unaffected. Alternatively, it could reimburse (selected) end consumers, allowing PLN to pass on the additional fuel cost via electricity tariff adjustments. Either way, a domestic tax obligation would safeguard affordable electricity in Indonesia while removing the bias towards the procurement and dispatch of coal power plants.

***Cap, tax and trade***

While the domestic market obligation subsidises coal, Indonesia's compliance-based carbon pricing instrument aims to impose a price on it, reflecting competing policy priorities. The government launched an emissions trading system (ETS) in 2023 for emissions from electricity generation. The first phase (2023-2024) covers 99 coal plants, all either PLN or IPP assets, that comprise >80 percent of total generation capacity. Coverage will be progressively extended to include generation assets in the second (2025-2027) and third phases (2028-2030) (ICAP, 2024). The ETS features an intensity-based emissions cap and distributes emissions allowances free of charge according to technology-specific emissions benchmarks. Producers can trade allowances to meet their compliance obligations and, from 2025 onward, will be subject to a carbon tax if they fail to do so. The price level of the carbon tax will be linked to the ETS allowance price in the secondary market.

**In its current form, the cap-tax-and-trade instrument does not alter incentives for fossil or renewable assets:**

- 100 percent free allocation at generously set emissions-intensity benchmarks that differentiate between technology subgroups 1) shield most emissions from the carbon price and 2) limit the cost differential between technologies with divergent emission intensities, inhibiting clean dispatch effects.

**RECOMMENDATION – introduce reforms to the cap-tax-and-trade instrument to induce merit order effects.** Generous allocation mechanisms and loosely set emissions caps are common features of newly established ETSs but need revision to drive emissions abatement once the instrument is fully established (Acworth et al. 2021; Kuneman et al. 2022). Two such revisions could be prioritised: introducing auctions for a gradually increasing share of primary allowance allocation; and replacing (sub)technology benchmarks with one uniform emissions-intensity benchmark for allocating the remainder of allowances. Over time, a (gradually declining) absolute emissions cap, aligned with Indonesia's net-zero pathway, should be introduced for the instrument to deliver an adequate price signal that levels the playing field for investment. On the back of such reforms, the cap-tax-and-trade mechanism will support renewables deployment by increasing the marginal cost of fossil assets, decreasing their utilisation rates and increasing their levelised cost of electricity (LCOE) relative to renewables.

A more ambitious ETS implies higher carbon prices, which will induce merit order effects and ensure cleaner generation sources are dispatched ahead of coal plants. IPPs will pass their carbon costs on to PLN as part of their variable OPEX. Moreover, PLN will incur carbon costs from its generation assets. These costs will have to be recovered. Following much the same logic as in the proposed domestic tax obligation for coal (above), there are two avenues for PLN to recover the carbon costs imposed by the ETS: 1) the government could use the auction proceeds to compensate PLN, preserving subsidised (or frozen) retail tariffs; 2) the government could use the auction proceeds to reimburse (selected) end consumers, allowing PLN to reflect carbon costs in the final electricity tariffs via the automatic tariff adjustment mechanism.

**RECOMMENDATION – policy sequencing: reform coal subsidies ahead of the cap-tax-and-trade scheme.** Whereas Indonesia's cap-tax-and-trade policy does not currently correct economic signals for renewables, the domestic market obligation disincentivises renewables deployment. It will be necessary both to reform the emissions trading system and remove the coal input subsidy in order to reveal the true costs of coal consumption. A more ambitious emissions trading system will increase the cost of electricity until sufficient renewable technologies are deployed. However, converting the domestic market obligation into a domestic tax obligation is a cost-neutral policy opportunity for Indonesia's power system that could be implemented in the near term. In removing the artificially reduced coal price, the introduction of a domestic tax obligation on coal supply would support clean electricity dispatch and clear the way for more effective carbon pricing in the long run. For these reasons, the domestic market obligation for coal should ideally be reformed first and then followed by a more ambitious cap-tax-and-trade scheme soon after.

### Market integration of VREs

Indonesia's 2020 grid code (MEMR 20/2020) supports the integration of variable renewables with two key measures: a priority dispatch rule and a specification that VRE curtailment is to be a last-resort option. However, these support measures come with some qualifications. As of 2024, MEMR is finalising a regulation with guidelines for renewable energy PPAs – following up on Presidential Regulation No. 112 of 2022. These include the following (MEMR 2024):

- In line with current arrangements, the PPA terms obligate PLN to purchase renewable energy output up to the contractually agreed energy volume.
- PLN must pay producers for deemed energy if the network cannot absorb the contractually agreed offtake volume.
- PLN may purchase electricity above the cotracted energy volume. If it does, it is entitled to pay a lower price.
- Renewable energy producers are subject to penalty charges if they produce less than the contracted energy during the course of one year (accounting for weather variability).

The PPA template provides renewable projects with priority dispatch and curtailment compensation up to their contracted energy volumes. Nonetheless, it imposes a volume and price risk on producers for output above and below the contracted energy. This risk appears asymmetric: renewable energy projects face revenue reductions in the case of underperformance (i.e. a financial charge in addition to reduced energy sales revenue) and lower revenue increases when production levels exceed expectations (i.e. lower offtake price or no offtake). The PPA also permits PLN to offset deemed energy payments (i.e. curtailment compensation) against the purchase expenses incurred by surplus renewable energy production. As such, IPPs may end up not receiving any net returns for the extra supply provided by their assets (Kuungana 2024).

**RECOMMENDATION – introduce profile flexibility into VRE PPAs.** The upcoming renewable energy PPA bases remuneration on a solar or wind plant's fixed annual production profile. Though this contract type supports PLN's operations with supply and budget predictability, it comes at a cost premium as investors must factor volume and price risk into their bids. Since PLN is not obliged to purchase generation volumes above the contracted level, the PPA structure also risks near-zero marginal cost electricity produced by well-performing renewable assets being curtailed. This is problematic from a system cost perspective. To address this issue, MEMR and PLN could opt for a pay-as-produced profile in renewable energy PPAs. This contract type would require PLN to purchase all output from variable renewables and is appropriate for power systems in the early stages of transition. Pay-as-produced PPAs mitigate the risk profile of VREs and support project bankability. This is likely to result in lower renewable energy tariffs, increasing VREs' competitiveness and supporting their deployment in the system. At today's negligible shares of variable supply, the priorities for Indonesia's power system are to attract investment in VRE and adopt measures to ensure that all variable supply is utilised. Pay-as-produced PPAs could help deliver on these.

Beyond contractual revisions, enhanced system operational practices would support the integration of variable supply. This includes introducing not only intraday unit commitments in dispatch (reducing reserve needs) but also advanced monitoring infrastructure for real-time data on supply, demand and the network (IEA, 2022a).

### PLN's business model

Indonesia's electricity value chain starts and ends with PT PLN. With the exception of on-site generation and isolated areas served by private power utilities, PLN owns most generation and all network assets in the country and is the sole electricity supplier. At roughly one third of on-grid generation capacity, the share of IPP-held assets has risen and is projected to continue to increase, yet IPPs operate under build-own-operate-transfer (BOOT) schemes and are obliged to transfer ownership to PLN at the end of their (30-year) power purchase agreements. As it has complete ownership and operational control of the sector, PLN is going to have to drive the large-scale shift to renewables. The preceding sections highlight the policy, market and regulatory opportunities that will enable it to do so. For PLN to be in the driving seat, however, its business model must be compatible with the investment requirements of an increasingly CAPEX-intensive system. This requires PLN's threefold challenge of low-cost recovery, low margins and low revenues to be addressed.

PLN's returns are based on a cost-of-service regulation which allows it to recover the cost of electricity generation (BPP) plus a margin (public service obligation) that has been set at seven percent since 2012. The BPP consists of variable expenditures (power purchases, fuel costs, O&M) and fixed expenditures (O&M, administration costs, depreciation, interest and cost of capital) and is expressed on a kWh basis for the previous year. The automatic tariff adjustment mechanism is applied irregularly and fails to capture the full spectrum of cost increases – especially capital costs and debt service obligations. The government compensates the ensuing difference between the final electricity tariff and PLN's costs plus public service obligation. In 2022, capital injections by the government (i.e. subsidy and compensation payments) totalled IDR 122 trillion, i.e. more than USD 7 billion (PLN, 2023c).

The government's financial guarantee has ensured PLN's solvency, but the revenue model falls short of equipping PLN with the financial strength it needs to turbocharge investments in renewables and networks.

- **The BPP revenue model does not anticipate future investment needs.** 1) PLN's revenues are benchmarked against the costs it incurred in the previous year and do not factor in future capital needs for RES deployment and network expansion. 2) The seven percent margin leaves PLN with a rate of return of approximately two percent, which is low even by utility standards. These numbers are not based on PLN's performance and solvency requirements but are the result of cross-ministerial negotiations (ADB, 2023). The low margins constrain PLN in accumulating equity and affect its financial ability to drive investment.
- **PLN is overleveraged.** With little internal equity, PLN has had to rely on debt to finance its operations. PLN's liabilities have increased year by year and reached IDR 646.7 trillion, or USD 43.6 billion, in 2022 (PLN, 2023c). PLN's debt-to-equity ratio fluctuates between 40 and 45 percent. Had it not been for an asset re-evaluation in 2015, it could have reached 170 percent (Hamdi, 2020). While the revenue constraints compel PLN to rely on debt, its inflated debt profile is largely a result of operational decisions, in particular the overbuild of baseload assets.
- **A borrowing cap and equity constraints limit PLN's investments.** Supported by a sovereign guarantee, PLN can issue low-yield bonds. However, the government caps PLN's borrowing at an annual IDR 50-60 billion (USD 3.1-3.7 billion) to keep government liabilities under control. The investment needs to keep up with transmission and distribution (T&D) network requirements are far greater and amount to some IDR 100-150 billion, according to one stakeholder consulted. PLN's equity base is too small to cover the shortfall.
- **State loss regulation hinders investment decisions.** Causing an (unlawful) loss to the state is a criminal offence under Indonesia's anti-corruption law. According to a constitutional ruling, assets and liabilities of state-owned enterprises belong to the state, exposing PLN's investment decisions to additional oversight. State auditors are reportedly involved in every step of the procurement process to check against state loss, extending lead times to the point where PLN is hindered from exhausting its (limited) investment budget. The state loss issue has also imposed a sense of personal liability on PLN staff, increasing the company's overall risk aversity.

In its current form, the cost-of-service model inhibits PLN from delivering the hardware required for a fast-tracked transition to renewables. Even so, PLN's financial woes stem in large part from a business strategy that is disconnected from global trends. A doubling down on the expansion of baseload generation in the face of less-than-projected demand growth has preempted VRE growth and saddled PLN with high system costs from fixed capacity payments. A new revenue model must be accompanied by a fundamental shift in strategy away from fossil baseload procurement and towards renewables, flexibility sources and network upgrades. While designing a new business model is beyond this assessment's scope, the following opportunities warrant consideration.

**RECOMMENDATION – improve PLN's financial sustainability to drive low-carbon investment**

- **A forward-looking rate of return component.** PLN's equity gap must be tackled if the company is to drive Indonesia's transition to renewables. The seven percent margin is proving insufficient to finance new investments. The government could consider reforming the revenue model with a forward-looking rate of return component for a net zero-aligned procurement pathway. This could be complemented by tariff reform aimed at recovering costs – complemented with targeted direct subsidies to selected consumer groups. However, the decision to recoup electricity network and generation costs from ratepayers or taxpayers is ultimately a political one.
- **Introduction of a separate network tariff.** Besides connection fees that constitute around two percent of PLN's revenue, no separate network charges apply. Introducing network (T&D) tariffs is a triple win: network tariffs would provide a clearer revenue model for PLN's T&D network investments, which must increase significantly in the coming years; similarly, network tariffs would enable PLN to outsource part of the investment needs to private parties; their introduction could be linked to a third-party grid access regime for decentralised renewable energy growth.
- **Introduction of ancillary services – reform PPAs with flexibility service provisions**. Indonesia's oversized coal fleet structurally impedes renewables deployment, reinforced by PPA structures that mitigate investor risk with sizeable capacity payments. This constitutes a sunk cost for baseload power. Redeploying capacity payments for flexibility services would ensure that existing system costs support the integration of variable supply and justify a shifting operational profile of the coal fleet.
- **Streamlined operations through a new single-buyer model.** Limited restructuring of PLN could mitigate conflicts of interest, increase transparency of business operations and bookkeeping and clear the way for cost-effective capacity procurement. This could take the form of a legally separate system operator with single-buyer functions (system planning, generation procurement, offtake and system operation) or a separate TSO/DSO entity with similar functions that furthermore owns and operates the grid. The ADB (2023) has developed a detailed roadmap for such a utility transition pathway in Indonesia.

## Recommendations

### Pillar 1 › Provide long-term investment certainty for variable renewable energies (VREs)

- **Scale up the VRE procurement pipeline and link it to revised long-term technology roadmaps (KEN and RUKN).** Ambitious planning is the key to stable, predictable policy support for VREs. Currently, Indonesia ranks bottom globally in installed capacity of variable renewables. An acceleration in technology deployment is overdue and imperative if Indonesia is to reach national RE targets and get on track to achieve net-zero emissions. Increased deployment of solar PV would also benefit Indonesia's nascent domestic industry. Targeted reforms of local content requirements, beyond those introduced in 2024, could further support it (see Investment regulations and market openness).
- **Introduce a revised tender scheme with a transparent scoring system and loosen PLN's equity ownership criteria in IPP projects to increase investor interest.** A transparent and publicly available scoring system would reduce incentives for biased bidding and help attract more bidders

for upcoming tenders. Loosening PLN's equity ownership criteria in IPP projects would lower investor risk, better position independent producers to mobilise capital and thereby attract more bidders. These measures could be coupled with improved implementation support, such as government support with siting and land agreements, grid connection costs and the introduction of a reformed renewable energy certificate scheme.

- **Remove the link between the price ceiling for VREs and the average cost of electricity generation (the BPP).** PR 112/2022 marks a significant improvement compared to its predecessor but fails to level the playing field for renewables. Where MEMR Regulation 12/2017 allowed renewables into the system if costs were below the BPP – the average cost of electricity – PR 112/2022 lifts that ceiling to the BPP itself. As a consequence, renewable project developers are still having to compete with subsidised coal-fired power plants whose dominant share in the power mix largely constitutes the BPP.
- **Introduce pay-as-produced PPAs for VREs to provide revenue certainty and de-risk investments.** Whereas coal power assets benefit from a fixed revenue stream secured throughout their power purchase agreement to recover capital and fixed costs, renewable energy assets are exposed to volume and price risk. Pay-as-produced PPAs for VREs would lower investment risk, support project bankability, yield lower tariffs and ensure that all VRE output in the system is utilised. They would create the necessary conditions to scale VRE investment in Indonesia's early-stage transition.
- **Support households looking to invest in rooftop solar with a net-billing scheme.** The revocation of net metering leaves DER deployment at a disadvantage in Indonesia. Net billing strikes a better balance by providing prosumers with temporal flexibility to recoup investment costs without disproportionately affecting utility earnings. The government could furthermore support low-income households with investment support schemes (Pillar 5).
- **Introduce third-party network access to capitalise on investor readiness to develop Indonesia's renewable energy sector.** Introducing a wheeling charge regime and the option for the private sector to conclude bilateral PPAs for renewable energy would be a breakthrough that promises to unlock private demand for renewables and spur deployment.

### Pillar 2 › Enhance system flexibility to integrate variable renewables into the system at the least cost

- **Remove dispatch distortions.** The domestic market obligation, a supply obligation and an input subsidy for the power sector incentivise the dispatch of coal power. Meanwhile, VREs face dispatch risk for supply above contracted energy volumes. We propose the following revisions.

    **1: Transform the domestic market obligation into a *domestic tax obligation*:** A DTO would retain the domestic obligation to supply coal but ensure international market prices are reflected in the electricity value chain, correcting dispatch and investment signals. It would generate tax revenue that could be used to offset fuel cost increases for PLN or tariff increases for end consumers. This renders it a cost-neutral no-regret option. (See this chapter's section "Market and contractual arrangements".)

**2: Provide priority dispatch for all VRE output to integrate and utilise the low-cost renewable energy available in the system.** While VREs benefit from priority dispatch, existing PPAs do not oblige PLN to purchase renewable output above contracted volumes. Adopting pay-as-produced PPAs, in line with international best practices, would ensure all variable supply is integrated and utilised in the system (see Pillar 1).

- **Value and unlock flexibility services that conventional assets can provide to the system.** Existing PPAs for thermal power (coal and gas) could be revised to include a flexibility or ancillary services component. This could take the form of performance criteria (ramp requirements, frequency control, re-active power, spinning reserve etc.) aimed at integrating variable supply. These system services could be remunerated out of existing capacity payments. This would redeploy sunk system costs for baseload availability towards system flexibility and justify a shifting operational profile of fossil fuel assets. Given the rigidity of existing PPAs, a contract renegotiation approach would need to be developed.
- **Enhance system operational practices by introducing intraday unit commitments and advanced monitoring infrastructure for real-time data on supply, demand and the network.** Such improvements have the potential to lower reserve requirements and optimise the utilisation of low-cost renewable energy assets (IEA, 2022a).

### Pillar 3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs

- **Revise planning and adequacy assessments for cost optimisation.** The planning reserve margin of 35 percent needs to be gradually lowered while at the same time adopting additional reliability metrics such as loss of load expectation (LOLE), loss of load probability (LOLP) and expected energy not served (EENS). These metrics allow for probabilistic assessments that can better anticipate and prevent contingencies as the share of VRE increases (IEA, 2022a). Stakeholder consultations on the energy master plans and RUPTLs could be institutionalised to increase the accuracy and robustness of modelling forecasts and their underlying assumptions.
- **Plan for flexibility needs.** With ample baseload and mid-merit power, PLN has sufficient technical capacity to accommodate variable supply sources over the coming years, yet it would be advisable to start planning for the greater variability observed at higher VRE shares. This could entail procuring peaker plants over the mid to long term while baseload units are retired, deploying storage technologies and introducing time-of-use tariffs to unlock quick wins in demand-side responses.
- **Introduce network tariffs.** Introducing network (T&D) tariffs represents a triple win for Indonesia: network tariffs would provide a clearer revenue model for PLN’s T&D network investments, which must increase significantly in the coming years; similarly, network tariffs would enable PLN to outsource part of the investment needs to private parties; furthermore, network tariffs (or wheeling charges) could be linked to a third-party grid access regime for decentralised renewable energy growth, which has not materialised so far.

### Pillar 4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets

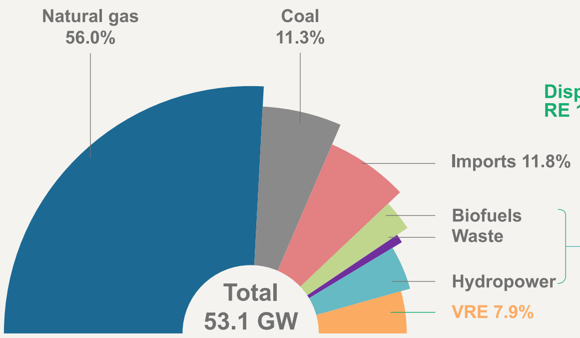
- **Halt the procurement pipeline (of 14 GW) of new coal power.** An overreliance on baseload power with highly revenue-secure PPAs obstructs near-term deployment of VREs. At reserve margins that are well above 35 percent and close to 50 percent in some regions, renewable capacity should substitute the current pipeline of additional coal lest system costs increase and the transition slow further.
- **Policy sequencing: Prioritise reform of the domestic market obligation for coal (Pillar 2) and continue with targeted reforms of the cap-tax-and-trade carbon pricing policy.** The introduction of a domestic tax obligation and targeted reforms of Indonesia's carbon pricing policy would reveal the economic costs of coal power and encourage its phase-out. Carbon pricing will not be effective while the use of coal remains subsidised. A domestic tax obligation on coal would ensure coal market prices are reflected along the electricity value chain (see section "Market and contractual arrangements"). Subsequently, a reformed cap-tax-and-trade instrument should ensure that coal's externalities are internalised to create a level playing field for renewable energy investment and dispatch. To this end, the following reforms of the instrument could be considered: gradually increase auction shares, shift to a uniform emissions-intensity benchmark and introduce an absolute emissions cap aligned with a zero-carbon power trajectory. Alternatively, a progressive and gradually increasing carbon tax could be instituted.
- **Reorganise the coal fleet to facilitate an accelerated entry of renewables into the power system: 1. repurpose, 2. reserve and 3. retire.** 1) Newer and more efficient assets should be repurposed for operational flexibility, supported by reformed PPAs (Pillar 2). This part of the coal fleet would support Indonesia's transition to renewables with a shifting production profile. It could include foreign-owned assets given the legal challenges in retiring these plants ahead of the duration of their PPAs. 2) Less efficient assets should be placed in a strategic reserve, reducing their operating cost to a minimum and creating market space for variable renewables to enter the system. 3) Least-efficient assets should be earmarked for early retirement with international support, such as from JETPs.

### Pillar 5 › Ensure affordable electricity for consumers while maintaining the sector's financial sustainability

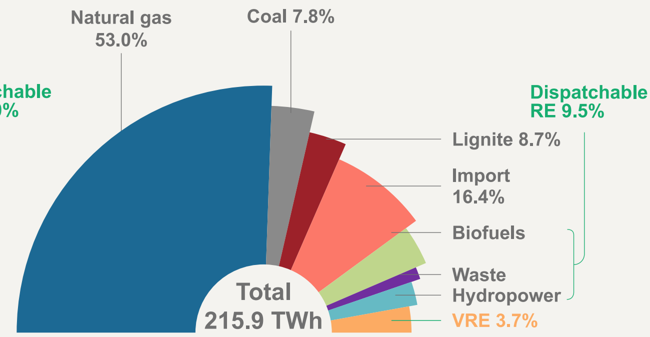
- Subsidies and tariff freezes have shielded Indonesia's population from the economic implications of an oversized coal fleet. Maintaining affordable rates now hinges on an efficient retirement of coal assets while VREs make inroads into the system.
- The government may need to consider fiscal support measures to enable PLN to deliver and mobilise the requisite investments for a transitioning power system. This would help maintain affordable electricity rates during a period of increased capital expenditures.
- The government could consider introducing rooftop solar investment support schemes for low-income households. The costs of such a scheme could be (partly) offset against the electricity subsidies these end consumers currently receive in the form of lower tariffs.

- With the shift from the domestic market obligation to a domestic tax obligation, retail tariffs could be adjusted to reflect higher fuel costs. Tax revenue could be used to reimburse selected end-consumer groups. A similar rationale applies to a reformed cap-tax-and-trade instrument, where auction proceeds could be used to offset electricity price increases.
- In the long term, retail tariffs may need to undergo further adjustments to reflect the cost of electricity, with appropriate guardrails for low-income households, to ensure that PLN can deliver the investments required for a clean, secure and affordable power system.

# 4 Thailand – A ring-fenced single-buyer system




Installed generation capacity in 2022




Electricity generation in 2022

**0.40**

Grid emissions factor ($tCO_2e/MWh$)

Source: EDGAR, 2023; EGAT, n.d.; EPPO, 2023; DEDE, 2023; Statista, 2024.

### Table 3. › Overview of key findings for Thailand*

| | Enabler | Barrier |
|---|---|---|
| **Investment certainty for variable renewables** | • Clear RE targets in the updated PDP and AEDP<br>• Fixed price FiT and long-term contracts create bankable PPAs<br>• Introduction of DPPA through third- party grid access unlocks an additional procurement model | • Excessive government intervention and lack of market competition slow renewables deploy-ment<br>• Uncertainty around tender rounds limit investment in VREs<br>• Lack of competitive bidding mechanisms in FiT round limits cost efficiency<br>• Lack of clear guidelines for DPPA transactions through the grid |
| **System flexibility and VRE integration** | • Merit order dispatching based on marginal costs<br>• The updated PDP incorporates BESS to enhance grid flexibility<br>• Introduction of demand response programme to reduce peak demand | • Rigid contract terms, including fixed-term con-tracts, take-or-pay obligations for gas supply and minimum-take requirements in PPAs<br>• Contractual commitments make curtailing gas power costly during low demand, reducing operational flexibility<br>• Insufficient grid infrastructure to go beyond the initial stages of VRE integration |

| | Enabler | Barrier |
|---|---|---|
| **System adequacy** | • Dynamic planning with probabilistic criteria (LOLE) | • High reserve margin strains system economics without necessarily enhancing reliability<br>• Minimum-take obligations force EGAT to purchase contracted volumes during peak and off-peak hours, risking financial losses if demand is low |
| **Phase-out of carbon-intensive assets** | • No new coal capacity in the updated PDP | • Lack of emissions-intensity considerations in dispatch operations |
| **Affordability** | • Uniform retail tariffs across regions<br>• Net billing programme | • Imbalance between fully hedged producers and fully exposed consumers with cost pass-through mechanism resulting in higher electricity prices<br>• Fixed payments inflate electricity prices<br>• Inefficient tariff adjustment mechanisms |

*recommendations are provided at the end of the chapter

Thailand's electricity industry transitioned to the state-owned enhanced single-buyer (ESB) model in 2003. Under this model, the Electricity Generating Authority of Thailand (EGAT), the primary electricity supplier and sole buyer that was established by the EGAT Act B.E. 2511 (1968) in 1969, is primarily responsible for electricity generation, procurement and wholesale distribution. To ensure transparency and accountability, EGAT ring-fences its generation and transmission assets through account unbundling. Despite introducing private participation from IPPs and small power producers (SPPs) in the 1990s and very small power producers (VSPPs) for RE generation in 2006, the sector remains shielded from competition and is predominantly controlled by state-owned entities (SOEs) alongside dominant market players.

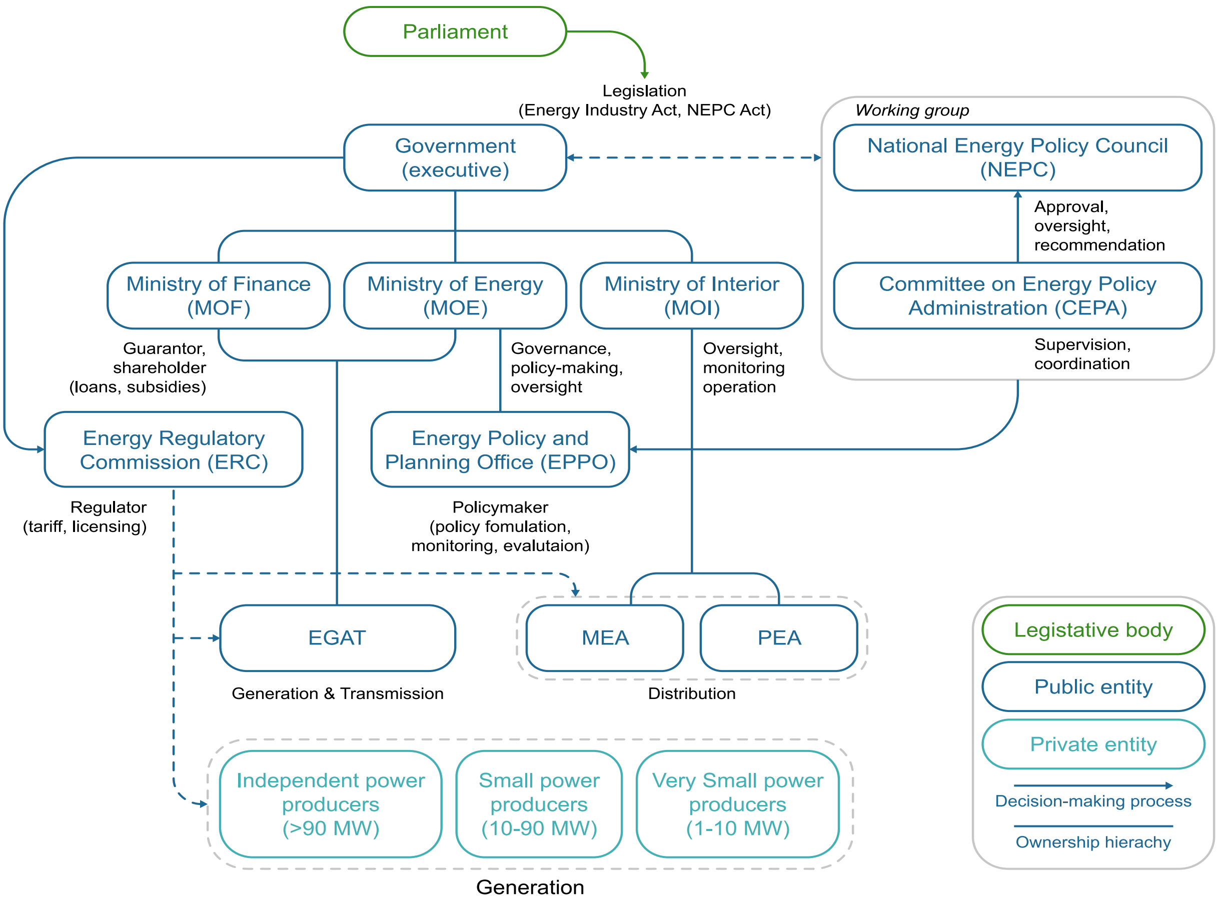
The National Energy Policy Office (NEPO) led the private sector's participation in electricity generation and established an IPP programme in which EGAT's subsidiary, the Electricity Generating Company Limited (EGCO), was the first participant in May 1992. Later, Ratchaburi Electricity Generating Holding Public Co. Ltd. (Ratchaburi) was established as an EGAT subsidiary and went public on the Stock Exchange of Thailand (SET) in October 2000, with EGAT retaining a majority share of 45 percent. In 1998, NEPO introduced a second-stage regulatory reform to boost market competition, coinciding with the State Enterprises Corporatization Act 2542 (1999) that was initiated after the Asian financial crisis. However, changes in government policy in 2002 led to NEPO being restructured to form the Energy Policy and Planning Office (EPPO), which now operates under the authority of the Minister of Energy. Subsequently, the military coup of 2006 brought a new government into power, leading to the adoption of the Energy Industry Act 2007 as the current primary regulatory framework aimed at promoting market competition by reforming the electricity sector's regulatory structure.

Thailand is aiming to achieve a 51 percent share of renewables in its electricity generation mix. It will still rely on gas-fired power generation for 49 percent of the total until 2037, as stated in the Power Development Plan 2024. The feed-in tariff regime has been crucial in increasing RE installed capacity – particularly solar – since 2007. The lack of competition in the market, combined with restricted quotas and uncertainty surrounding procurement cycles, has constrained investment in renewable energy thus far. To meet long-term renewable energy targets, reforms must be introduced to enhance procurement efficiency, ensure fair pricing, and mobilize investment.

Recent initiatives such as the introduction of direct PPAs (DPPAs) and a third-party access (TPA) regime aim to support ambitious clean energy goals such as RE50/100. They are being introduced to attract foreign investment in data centres and new S-curve businesses as demand for green electricity increases. The DPPA, with a 2 000 MW quota specifically for data centres through TPA, represents a significant step towards allowing direct transactions between power producers and large consumers, thereby bypassing the traditional ESB model. Such efforts are part of broader reforms to restructure the market to encourage greater private-sector participation, reduce incumbent SOEs' market influence and implement provisions for TPA in electricity grids – which is essential for establishing a fully competitive electricity market and ensuring fairness and equitable market participation. Recent regulatory sandboxes for new business models (e.g. Phase I and II projects such as P2P electricity trading, virtual power plants, battery storage etc.) are also being developed. Additionally, regulatory support is being enhanced to meet increased demand for clean energy from the private sector, including initiatives such as Renewable Energy Certificates (RECs) and Utility Green tariffs (UGT).

## Institutional structure

**Figure 5. › Institutions and governance of Thailand's electricity sector**



## Core institutions and legislative processes

The energy sector in Thailand is overseen by the National Energy Policy Council (NEPC), established in 1992 under the National Energy Policy Council Act. The NEPC acts as the main authority for reviewing and approving proposals concerning national energy policy, regulation and the development of the energy sector and reports directly to the cabinet. Its core objective is to bolster energy security, diminish reliance on imported energy and ensure the affordability and sustainability of energy resources. The NEPC board consists of 19 high-level policy- and decision-makers, including 11 cabinet ministers, a deputy prime minister and other key government officials, with the Prime Minister serving as the ex-officio head. Despite its comprehensive structure, the NEPC's focus on political agendas and its lack of direct access to technical information can lead to misalignment with operational realities, especially when there is no clear policy or strategic direction for energy. This highlights the need for more effective governance and clearer delineation of authority.

Over the past three decades, three government departments have shaped the NEPC and its decisions: the Ministry of Energy group, the Ministry of Finance group and the Prime Minister's office group, each of which hold multiple seats.  In addition, the Committee on Energy Policy Administration (CEPA), chaired by the Minister of Energy, was instituted to assist with the work of the NEPC. Its roles include advising on the formulation of national energy administration and development policies, as well as setting energy prices and contributions to the Oil Fund in line with NEPC guidelines (see Figure 5. Institutions and governance of Thailand's electricity sector

The Ministry of Energy (MOE) is the main authority responsible for overseeing the operation of Thailand's energy sector. It develops and implements the country's energy policies, regulations and development initiatives. EPPO plays a crucial role in administering national energy planning, formulating energy-related policies such as the Power Development Plan (PDP) and Alternative Energy Development Plan (AEDP), proposing development plans to the NEPC and serving as the secretariat to the NEPC and CEPA. Furthermore, the Energy Regulatory Commission (ERC), established under the Energy Industry Act of Thailand, is responsible for regulating operations in the domains of both electricity generation and natural gas. It sets electricity tariffs, issues energy licences and protects consumer interests.  For state-owned utilities, EGAT is under the supervision of both the MOE and the Ministry of Finance (MOF), reflecting its roles in energy generation, energy acquisition, electricity sales and financial management. On the other hand, Thailand's distribution utilities – the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA) – are under the jurisdiction of the Ministry of Interior (MOI), highlighting their focus on providing electricity services to urban and provincial areas respectively.

## Legislative framework and regulatory establishment

Two key legislative acts, namely the Energy Industry Act B.E. 2550 (2007) (as amended) and the Energy Conservation Promotion Act B.E. 2535 (1992) (as amended), are fundamental in shaping the RE landscape in Thailand. The Energy Industry Act is the primary legislation governing the power generation sector. Through this Act, the ERC was established in 2008 with a mandate to regulate the energy industry, aiming to enhance transparency and fair competition by separating policymaking, regulation and operation from the MOE and three utilities. The Energy Conservation Promotion Act focuses on energy efficiency and conservation, particularly in sectors such as industry and buildings. By encouraging sustainable energy practices, the Act provides financial and policy support aligned with Thailand's energy conservation objectives.

Prior to 2007, private power operators faced restrictions on electricity operations under the Declaration of the Revolution Council No. 58. Thailand's Energy Industry Act addressed this issue by introducing a licensing system for operators, allowing private electricity sales and implementing regulatory measures to promote competition and the use of RE sources (Eiamchamroonlarb, 2022). However, acquiring licences for RE production capacities is hindered by a convoluted process involving multiple regulatory bodies that applicants must navigate (Aggarwal & Usapein, 2023).

To support RE growth, the ERC could adopt a more proactive approach to reducing market entry barriers, promoting competition, and encouraging investment in low-carbon energy sectors. Additionally, the ERC should ensure that its regulation of service rates does not affect electricity tariffs while it promotes supply decarbonisation and market efficiency. The ERC's initiatives should align with the national strategic plan and could include assessments of the contours of potential future electricity market models.

## Market structure

Thailand's electricity sector is structured along one integrated transmission system operator (TSO) and two integrated distribution system operators (DSOs) that each own network and generation assets and procure, sell and deliver energy to consumers. EGAT holds a monopoly on high-voltage transmission and is responsible for the planning and procurement of electricity, which it sources from various producers, including IPPs (> 90 MW), SPPs (> 10-90 MW) and its own assets (comprising small and large plants). IPPs operate large-scale power facilities such as thermal, combined-cycle and gas-fired power plants and conclude long-term contracts with EGAT. Additionally, EGAT acts as the system operator. Its National Control Center (NCC) dispatches the generating fleet under the ESB model and manages regional power systems through five centres – Metropolitan, Central, North, Northeastern and South — in coordination with the MEA's and PEA's distribution control centres. This model maintains transparency and ensures the equitable dispatch of electricity from both IPPs and EGAT-owned generation (Sirasoontorn & Koomsup, 2017). EGAT supplies wholesale electricity to distribution utilities and their direct customers via its transmission network. EGAT's transmission network operates at standard voltage levels of 500 kV, 230 kV, 132 kV, 115 kV and 69 kV, all at a frequency of 50 Hz, and is interconnected by 238 substations. There is also a closed-system high-voltage direct-current (HVDC) connection operating at 300 kV between Thailand and Malaysia.

Thailand's integrated DSOs, the MEA the PEA, own the distribution grids. They procure electricity from VSPPs (1-10 MW), operate the distribution system and are the retail providers for their respective service areas. MEA serves 4.11 million customers in its distribution area, covering Bangkok, Nonthaburi and Samut Prakan (excluding public lighting), with voltage levels of 69 kV, 24 kV, 12 kV and 0.4 kV. The PEA, on the other hand, spans 74 provinces and thus covers the remainder – i.e. over 99 percent – of Thailand's territory. It delivers electricity to 21.2 million customers and manages distribution lines at standard voltage levels, including 115 kV, 69 kV, 33 kV, 22 kV and 0.4 kV.

In addition, Thailand has significant cross-border interconnector capacity with Laos in the north, Cambodia in the east and Malaysia in the south. However, there is currently no interconnection with Myanmar; only a preliminary study of its potential exists. EGAT is responsible for procuring cross-border supply and overseeing the interconnection lines. The Lam Takhong pumped hydro storage project, with a capacity of 1 GW (4 x 250 MW), is an asset that boosts Thailand's power system flexibility. The plant in northeast Thailand accounts for 25 percent of the country's installed hydroelectric capacity and is the largest in Southeast Asia.

### Market players

EGAT holds a central role in both power generation and transmission. Distribution is shared between state-owned entities, namely MEA and PEA. Over time, IPPs' share of electricity generation has experienced fluctuations, peaking at 35 percent in 2017 before dipping to 33 percent in 2022, while

EGAT's stake in generation capacity has gradually declined to 30 percent (EPPO, 2024). Approximately 12 percent of the power supply is imported from neighbouring nations such as Lao PDR and Malaysia, with the rest being procured from VSPPs. It is anticipated that the participation of private actors through IPPs, SPPs and VSPPs will continue to grow and play an increasingly crucial role in power generation.

**Table 4. › Power producers in Thailand**

| Power producers | Installed capacity (MW) | Main technology types |
|---|---|---|
| EGAT | 16 237 | Thermal, combined cycle, hydropower, RE, diesel |
| IPP (>90 MW) | 17 649 | Thermal, combined cycle, gas-fired |
| SPP (10−90 MW) | 9 483 | Thermal, combined cycle, cogeneration, RE (e.g. solar, wind, biomass, biogas) |
| VSPP (1−10 MW) | 4 248 | RE (e.g. solar, wind, biomass, biogas) |
| Import | 6 235 | Hydropower, thermal, HVDC line |
| **Total** | **53 852** | |

Source: EPPO, 2024

EGAT purchased energy from 12 IPPs in 2023 accounting for 17 649 MW of installed capacity in mostly gas and some coal assets (Table 4). These include key players such as Ratchaburi Electricity Generating Holdings, Gulf and Glow IPP. Recent years have seen a rise in the number of SPPs, which sell power primarily to EGAT, including from renewables. The contribution of VSPPs has increased too. VSPPs generate electricity from renewable sources for self-use and authorised sales to MEA or PEA through the FiT programme, which has been in operation since 2007. Legal frameworks, along with higher renewable energy tariffs for SPPs and VSPPs, have enabled a faster expansion since 2007, yet installed capacity, at 13 721 MW, remains well below potential. With the latest FiT round, this number will increase to approximately 17 000 MW by 2030 (ERC, 2024).

Natural gas continues to be the largest source of electricity generation, contributing more than 50 percent of total power output, with coal and renewable energy sources following closely behind. Natural gas is obtained from three main sources: domestic production, including the Gulf of Thailand and the Malaysia-Thailand Joint Development Area (MTJDA), imports from Myanmar and imported LNG. Long-term contracts (15-20 years) for LNG have been secured with major suppliers such as PTT, Qatar, Shell, BP and Petronas. However, these contracts cover only six percent of the total gas supply projected for 2037, indicating a need for potential new gas resources and LNG imports to meet the anticipated 37 percent supply requirement (Draft Gas Plan, 2024).

Following the current gas liberalisation plan Phase II, Thailand has expanded its LNG import capabilities through spot purchases and imports agreed with new shippers, issuing eight licenses to entities such as EGAT, Gulf, BGRIM, EGCO, PTTGL and SCG. Most of the demand for gas comes from the regulated electricity market (EGAT, IPPs and SPPs), supplied at pool prices by PTT under daily contract quantity[6] (DCQ) contracts. These contracts specify the minimum gas quantity that the seller must deliver and the offtaker must buy each day based on minimum offtake commitments within the PPAs. These fixed-term agreements, covering a significant portion of the total gas supply and tied to fixed terms, lock gas-fired power into the system for years to come. Given the current conditions of oversupply, these commitments inhibit the operational flexibility of the power system and render it more costly to integrate variable renewables.

[6] Daily contract quantity: the quantity of gas that the seller must deliver to the buyer according to the contract on each day

Thailand's power system has faced generation overcapacity and a high reserve margin in recent decades. The reserve margin has hovered around 36 percent, exceeding the recommended level of 15 percent of peak power demand (Chongphipatmongkol & Audomvongseree, 2018). A preference for surplus capacity and historical overestimations of GDP and electricity demand growth have resulted in an overbuild of assets and excessive procurement through PPAs that include minimum-take requirements. To integrate new renewable capacity at the least cost, no more baseload capacity must be added to the system; existing capacity in gas assets can serve to accommodate variable output from renewables by ramping up production during evening and night hours.

**RECOMMENDATION – dynamic planning using LOLE and EENS.** Incorporate loss of load expectation (LOLE) and expected energy not served (EENS) metrics into energy planning frameworks to dynamically evaluate and adapt reserve margin requirements. This approach will support the integration of renewable energy by better aligning system capacity with actual system needs.

Generation capacity planning is guided by the Power Development Plan (PDP), a 20-year master plan for power generation and supply. Since 1992, EPPO has been responsible for formulating the PDP and updates it every three to four years to match evolving needs and priorities. The current version, PDP 2018 Revision 1, was published in 2020. In June 2024, a draft of PDP 2024 (2024-2037) was announced for public hearing, aimed at increasing the share of generation capacity accounted for by renewable energies to 51 percent by 2037. The details presented in the draft version are not expected to change pending approval.

Thailand plans to maintain a 41 percent share of power generation from natural gas by 2037, which presents challenges in terms of meeting long-term carbon-neutrality goals. The average electricity rate for the draft PDP 2024 plan is estimated to be 3.8704 baht per unit, which is less than the 3.9479 baht per unit laid down in PDP 2018 Revision 1. The country's 2nd Updated NDC (2023) targets a 40 percent reduction in greenhouse gas emissions by 2030 compared to business-as-usual scenarios, with energy and transportation sectors accounting for the majority of reductions.

**Table 5. › Comparison of current policy planning and latest public hearing updates**

| | Current policy planning (2018-2037) | Public hearing version (2024-2037) |
|---|---|---|
| **Power Development Plan** | • Increase overall generation capacity to 77 GW by 2037<br>• Utilise 46 GW from existing operations until 2017, adding 56 GW from newly established facilities and retiring 25 GW of capacity from 2018 to 2037<br>• Most new capacity will be derived from natural gas-fired power plants (39%), renewable energy power plants (primarily solar PV, at 33%) and coal-fired power plants (5.6%) | • Increase overall generation capacity to 112 GW by 2037<br>• Utilise 53 GW from existing operations until 2023, add 77 GW from newly established facilities (including BESS and pump hydro storage) and retire 18 GW of capacity from 2025 to 2037<br>• 51% of total electricity generation to come from renewables by 2037 (17% from solar, 17% from domestic and imported hydro and 17% from other renewables, with the remaining 41% from natural gas and 7% from coal-fired power plants<br>• Blend hydrogen with natural gas at 5% from 2030 |

| | Current policy planning (2018-2037) | Public hearing version (2024-2037) |
|---|---|---|
| **Alternative Energy Development Plan** | • Increase the share of renewable energy in electricity, heat and biofuels by 30% in 2037<br>• Renewable energy electricity production to reach 29 GW by 2037<br>• Solar energy to comprise majority share, solar PV 12 GW, floating PV 2.7 GW, accounting for around 40% of total renewable energy capacity by 2037 | • Increase the share of renewable energy in electricity, heat and biofuels by 36% in 2037<br>• Renewable energy electricity production to reach 73 GW by 2037, with the majority share coming from solar PV at 39 GW (33.6 GW from PPA and 5.4 GW from IPS), 2.7 GW from floating PV and 9 GW from wind |
| **Gas Plan** | • Forecasted natural gas demand to increase by 0.7% annually<br>• Estimated demand: 5 348 million standard cubic feet per day by 2037<br>• Additionally procure natural gas or LNG beyond existing contracts, accounting for approximately 68% of total procurement by end of plan period | • Forecasted natural gas demand to decrease due to the higher proportion of renewable energy in electricity sector (from 36% to 51%)<br>• Estimated demand: 4 747 million standard cubic feet per day by 2037<br>• Additionally procure natural gas or LNG beyond existing contracts, accounting for approximately 37% of total procurement by end of plan period |
| **Energy Efficiency Development Plan** | • Reduce energy intensity to 30% of the 2010 baseline by 2037 | • Reduce energy intensity to 36% of the 2010 baseline by 2037 |
| **Oil Plan** | • Sufficient oil reserves are available to last at least 50 days<br>• E20 to meet at least 90% of gasoline demand by 2027<br>• Produce Euro 5 diesel to meet 100% of demand by 2024 | • Phase out Gasohol E10 (91) sales by 2025<br>• Implement Gasohol E10 (95) and E20 as primary gasoline alternatives<br>• Develop regulatory framework and investment support for hydrogen fuel |

## Investment regulations and market openness

Thailand has been successful in attracting foreign investors. In a 2022 initiative, the ERC announced the Utility Green Tariff (UGT) to promote the use of clean energy in the industrial sector and to attract foreign direct investment. However, foreign ownership in project companies is capped at 49 percent and most members of project companies' boards of directors must be Thai nationals. Companies eligible for specific commitments under international agreements in modes 3[7] and 4[8], and those exempted under other laws, may qualify for exemptions from the foreign shareholding and director requirements (ERC, 2022). These are rarely granted in practice, however. To own up to 100 percent of shares in Thailand, foreign investors must establish a company in compliance with Thai law, first obtaining a Foreign Business License (FBL) and adhering to the regulations outlined in the Board of Investment Promotion Certificate.

Thailand has no specific local content requirements (LCRs) for RE projects in Thailand. Yet,

[7] **Mode 3 (Presence of natural persons):** Allows companies to send individual service providers (such as consultants or engineers) to another country to work.

[8] **Mode 4 (Supply through electronic means):** Allows companies to deliver services electronically across borders (such as online education or software)

preference is given to local bidders in auctions. This includes community-based RE auctions in which selected bidders must collaborate with locals and establish a memorandum of understanding (MOU) for joint investment. The memorandum requires that the financial returns equivalent to a ten percent ownership stake in the project are directed towards social and welfare development.

### Third-party grid access

Restrictions on private-sector electricity sales limit the growth of Thailand's nascent renewable energy sector. The market for renewable energy electricity production remains largely within the domain of the ESB model that involves Thailand's offtakers (EGAT, MEA, PEA) procuring new capacity in line with the PDP and awarding utility PPAs to selected producers. The ERC oversees the renewable energy project pipeline with auction rounds, the frequency and size of which are part of a centralised planning process largely outside the influence of private actors willing to supply or procure renewable energy at greater speed.

Expanding the scope of renewables deployment beyond centralised procurement processes requires power wheeling charges and third-party access to the grid to be introduced. Commercial and industrial (C&I) consumers are seeking ambitious clean energy procurement goals such as RE100. Third-party access (TPA) provides increased business opportunities for VREs to spur deployment rates. Implementing a third-party access regime would enable investors, project developers and companies at various locations to enter into bilateral contracts directly. PPAs are currently limited to on-site generation (within industrial estates) or involve the installation of solar rooftops on the premises of electricity buyers.

In response to these limitations, the government announced a pilot project enabling private players to bilaterally procure renewable energy through direct PPAs (DPPAs), facilitated by third-party grid access and in effect bypassing the ESB model. The pilot is exclusively available to data centres and new S-curve businesses committed to renewable energy use and sets a procurement cap of 2 000 MW. The initiative mandates adherence to consistent operational standards and substantial capital investment. Electricity procured under this initiative cannot be resold into the national grid (refer to Figure 6). The TPA framework, including service charges such as wheeling charges, connection charges, ancillary services, imbalance charges, policy expenses and related fees, is scheduled to be completed by the end of 2024. However, developers have raised concerns that quotas might limit participation to a select few with access to better information.

**RECOMMENDATION – accelerate the enforcement of the third-party access grid codes.** Establish fair wheeling charges and network system service fees to balance grid access and cost. Additionally, clear and transparent criteria for network access are needed to ensure fairness and equity between developers and consumers.

## Policy instruments for VREs

RE technologies benefit from various support policies that aim to increase deployment in line with the PDP's technology projections. Electricity procurement from renewable energy power plants operates according to the RE zoning principle, which determines the types and quantities of renewable energy by region/province annually in line with the PDP and AEDP framework. By 2023, Thailand's installed solar PV capacity had exceeded 8.8 GW. The solar PV growth trajectory is driven by both economic factors (solar PV being one of the cheapest energy generation technologies available) and governance factors.

Under the AEDP 2024, the government has set targets to achieve a 36 percent renewable energy share of total energy production by 2037 and for this to increase to a minimum of 50 percent by 2050. Specifically, the AEDP aims to reach a total RE generation capacity of 73 GW by 2037 (a three-fold increase by comparison with AEDP 2018), with VRE sources accounting for 72 percent of the targeted capacity (Table 4). Achieving these targets necessitates a major ramp-up: REs accounted for just over 13 percent of total output in 2023, the majority being from biomass and less than four percent of total power generation from VREs. No official short- or medium-term targets have been established for VRE that would allow progress to be monitored towards the longer-term goals for 2037 and 2050.

### Feed-in tariff regime

Feed-in tariff (FiT) schemes have driven the growth of solar power since 2007. These schemes take two main forms: premium-price FiT payment, also known as Adder, and fixed-price FiT (pre-specified tariff) payment. Adder involves a normal tariff combined with an additional premium rate, which was initially used to drive the growth of utility-scale solar power. In Thailand, determining the appropriate FiT payment varies by energy source: solar and wind projects use only the fixed FiT (FiTf) rate, which covers the construction costs of power plants and their operation and maintenance (O&M) expenses. In contrast, biomass and biogas projects involve both the FiTf rate and the variable FiT (FiTv) rate, which covers the cost of raw materials used in electricity production and increases according to the core inflation rate. Additionally, there are special premium incentives for projects located in Thailand's three southernmost provinces (Pattani, Yala and Narathiwat) to encourage RE development in these areas.

Renewable energy deployments in Thailand have so far targeted small- (utility-) scale projects (SPP and VSPP), which may involve either firm- or non-firm contracts, depending on the technology. Initially, the government provided attractive incentives, including the Adder rate of 8 baht (THB) per unit for ten years, with contract payments starting in December 2011 for utility-scale solar power with total installed capacity of 969 MW. This rate was later revised to THB 6.5 per unit in 2010. In 2013, Thailand implemented FiT Phase I for solar rooftop projects. The FiT rate was set at THB 6.5 per unit for C&I systems (10-250 kW) and THB 6.96 per unit for residential systems, with a 25-year contract. FiT Phase II followed in December 2015, offering THB 6.85 per unit for residential rooftop systems and THB 5.66 per unit for Adder leftover and government cooperative projects, also running until December 2040. The combined total capacity for both phases is 130 MW. Wind power plants receive an Adder payment of THB 3.5 per unit for ten years, with contract payments commencing in January 2012 and concluding in April 2029.

In line with these developments, the latest round of renewable energy procurement under the FiT scheme for the period 2022-2030 involved fixed pricing (pre-specified) payments with a contract term of 20-25 years, projects undergoing corporate qualification and technical assessment based on five readiness criteria (land availability, technology suitability, fuel accessibility, financial viability and project implementation planning), with scores being given for each area. Projects must meet a minimum score in each area to be eligible for a PPA. This process resulted in an allocation of 5 GW across four project types in 2022: biogas (335 MW), wind (1.5 GW), ground-mounted solar (2.3 GW) and ground-mounted solar plus battery energy storage systems (BESS) (1 GW). Each project type receives FiT throughout the project duration. PPAs for ground-mounted solar plus BESS are available only to SPPs and under a partial-firm contract, while other types of projects are available to both VSPPs and SPPs and operate on a non-firm basis.

The second phase of the tender, with a projected capacity of 3.66 GW, will mainly include ground-mounted solar, ground-mounted solar plus battery energy storage systems, wind energy and industrial waste-to-energy. However, the timeline has not yet been established. Despite the promising allocation, concerns have been raised regarding transparency and the selection criteria in the procurement process. Specifically, some electricity producers have voiced concerns to the Federation of Thai Industries (FTI) about the lack of transparency and advance notification of selection criteria for bidders, underscoring the need for continued improvement in policy implementation and stakeholder engagement.

In Thailand's single-buyer system, utility PPAs dominate the renewable energy market, with electricity being sold to EGAT, MEA or PEA. As a result, deployment rates rely almost exclusively on the government's discretion in launching new tender rounds, whose frequency and (capacity) size are not yet on a par with a net-zero trajectory. The following aspects should be considered to optimise centralised procurement:

- **Limited procurement quota:** Small procurement quota set for RE and uncertainties of procurement opportunities hinder long-term RE objectives. The latest FiT scheme in 2022 revealed a high readiness among investors to roll out renewables, with 17 400 MW in applications for a 5 000 MW quota (ERC, 2022). This signals opportunities for a larger procurement pipeline with competitive selection.
- **Cost competition:** The absence of an auction or open competition bidding process limits price discovery. As FiTs are fixed, participants cannot compete on the basis of cost criteria, potentially leading to missed opportunities for cost savings.
- **Transparency issues in the procurement process:** Concerns raised by stakeholders regarding the transparency of the selection criteria and lack of advance notification of selection criteria for bidders indicate a need for clearer guidelines and transparency in the procurement process.
- **Procurement process complexity:** The complexity of the procurement process, as evidenced by the eligibility assessment and technical evaluation criteria, may deter some potential bidders and contribute to delays in project development, posing challenges to the timely market deployment of RE.
- **Capacity constraints:** The availability of PPAs on a "non-firm" basis (pay-as-produced) is limited, yet it does provide revenue certainty and ensure bankability. The use of non-firm contracts should be expanded to support large-scale renewable energy projects and meet technology targets.

**RECOMMENDATION – implement a competitive procurement framework for large-scale projects and ensure capacity alignment and transparency.** Building on Thailand's high investor readiness and large number of potential bidders, a move to competitive auctions could lower the cost of VRE contracts. Best practices for design can be found in IRENA and CEM (2015). This should be supported by transparent communication about new auction rounds, including their application and selection process, in order to solicit bids and increase investor certainty. Furthermore, the policymaker, the regulator and the three utilities (MEA, PEA EGAT) could improve their coordination to ensure that capacity planning for VREs is adequately reflected in the procurement schedule and supported with the required grid investments.

### Distributed PV (DPV)

Investments in rooftop solar have the potential to contribute significantly to Thailand's renewable energy targets. Projections indicate that the technical capacity for rooftop solar energy could reach approximately 226 GW by 2037, while the market potential is estimated to be around 9 GW (Tongposit et al., 2024). As of 2022, the total installed capacity of rooftop solar installations in Thailand was approximately 1.8 GW, driven mainly by self-consumption installations since 2018 (DEDE, 2023).

The government has promoted solar rooftop installations through VSPP PPAs under its FiT programme since 2013. Prior to this, there were other initiatives to encourage solar power, such as the Adder rate programme introduced in 2007. The financial incentive was so attractive that applications for licensing exceeded Thailand's solar power targets in terms of capacity. However, uncertainties surrounding solar power capacity additions hindered the three state-owned utilities from expanding T&D networks to accommodate unforeseen demand. This surge in licensing applications led to network constraints. In response, PEA, MEA and EGAT ceased accepting new PPAs in 2010 until project assessments had been completed, including evaluations of technical feasibility, network capacity and risk analysis. This led to a pause in solar power support that lasted until 2013 (Sirasoontorn & Koomsup, 2017).

Later that same year, the ERC issued the regulation "Power Purchase from Solar PV Rooftop, B.E. 2556" and introduced a FiT programme for rooftop DPV systems, aiming to generate 200 MW of solar power. Despite commercial success, residential uptake fell short, with around 55 percent of the targeted residential capacity being installed. Though early adopters from high-income groups showed financial readiness, incomplete submissions and barriers such as short application periods and complex permit processes hindered growth. The FiT programme was discontinued thereafter.

In 2016, while it evaluated technical issues, the NEPC initiated a Rooftop PV Pilot Project targeting 100 MW in capacity additions and focusing on self-consumption of generated electricity, without any compensation for surplus generation. The grid code associated with this pilot project imposes restrictions on PV system size based on the voltage level of the connected line. For instance, DPV systems connected to low-voltage lines are limited to 5 kW for one-phase lines and 10 kW for three-phase lines. These size limitations often result in PV production not exceeding the load, resulting in minimal back-feed to the grid. However, the number of subscriptions was low, amounting to only 5.63 MW of the 100 MW targeted by the pilot project (PVGIS). There was no policy support until May 2019, when the government introduced a new net billing programme limited to residential users with PV rooftop systems capped at 10 kW each. Initially, the export rate was set at THB 1.68/kWh (below the average wholesale electricity rate), which was later revised to THB 2.20/kWh in 2021. This programme is ongoing, with MEA and PEA currently purchasing the excess electricity generated from residential-scale DPV systems.

**RECOMMENDATION – regularly review solar export rate.** Thailand should implement periodic reviews of the export rate, which is currently set at THB 2.20/kWh under the net-billing scheme. These reviews should reflect the overall value of solar power and consider factors such as operational costs and network investment requirements. The goal is to ensure the purchase rate remains fair and reflective of market conditions, promoting growth in the solar energy sector while avoiding any undue financial burden on ratepayers.

As of 2024, a self-consumption scheme has been available to all consumer groups without any quota restrictions. In contrast, the net-billing scheme in Thailand imposes a quota of 90 MW for residential customers with rooftop solar systems not exceeding 10 kW. This specific target customer segment and system size limitation distinguish the net-billing scheme from the self-consumption scheme. Nevertheless, these schemes play an important role in expanding Thailand's prosumer base, especially given the lack of long-term certainty surrounding support mechanisms for DPV electricity. Industrial consumers with installations below 1 MW no longer require a factory licence under current regulations (Ror Ngor. 4). Efforts are underway to waive the requirement for a factory licence for capacities exceeding 1 MW.

However, there are still barriers hindering the installation of DPV systems according to the grid codes of the two distribution utilities. The total capacity of each transformer must not exceed 15 percent of the transformer capacity for low voltage connection. Additionally, there is a requirement to install zero-export controllers or reverse power relays to prevent excess generation from being fed into the grid, thus limiting full utilisation of the solar capacity (MEA, 2023).

**Several challenges need to be addressed to scale up distributed VRE deployment:**

- **Policy and regulatory uncertainty:** Inconsistent or evolving policies and regulations in the VRE sector create uncertainty for investors and developers, affecting project feasibility and investment decisions. Moreover, the lack of clarity regarding electricity purchases from VRE sources compounds this challenge. Despite rooftop solar's high DPV potential, there are currently no long-term rooftop solar targets or programmes for commercial and industrial users. Introducing new programmes, for example to support PV installations with battery storage, should be considered to align with grid-planning capabilities and provide flexibility through demand responses.
- **Lengthy VRE lead time:** Unpredictable permitting processes and bureaucratic hurdles arising from complex permit and licensing systems prolong the lead time and result in increased transaction costs. Project developers need to engage with multiple entities during the permission process. To streamline this process, reduce time and cut costs for project developers, a one-stop service should be established.
- **Surplus DPV electricity injection limitation:** This restriction hampers DPV installations' ability to feed excess energy into the grid. Installing zero-export controllers curtails the full utilisation of solar capacity, potentially impacting the viability of DPV systems for consumers.
- **Disadvantageous DER grid codes:** Power plants face substantial expenses for connection, including technical assessments and fees, that potentially encompass transformer and transmission line costs for unsupported connection points. Diverse and inconsistent grid codes defined by utilities such as EGAT, MEA and PEA further complicate RE integration.

### Renewable Energy Certificate (REC) initiatives

EGAT governs REC issuance in Thailand by verifying the generation of renewable electricity, ensuring there is no double counting in national grid emissions and complying with the I-REC standard for REC issuance. EGAT oversees the process of transferring one megawatt-hour (MWh) of renewable electricity into one REC, adhering to established standards. As of 2023, a total of 9 522 000 RECs have been issued, the majority of renewable energy generation coming from hydropower, biomass and solar (EGAT, 2024). The issuance of RECs in Thailand is continuously increasing, reflecting consumers' growing demand for renewable electricity – particularly from international companies committed to reaching their RE commitments. However, REC buyers are concerned that the existing registered RE generation capacity will not be sufficient to fulfil the increasing demand for RE electricity and RECs. As regards the applicability of I-REC, there is also emerging concern that it may not be recognised as a quality offset under CBAM and other corporate decarbonisation directives. Recent transactions show that EGAT-issued I-RECs are priced at 0.95 US dollars each, which is notably lower than the average price of 2.50 US dollars per tonne under the Thailand Voluntary Emission Reduction Program (T-VER). This discrepancy raises concerns about the market value and economic viability of I-RECs compared to other certification options (Kasikorn,2024).

### Utility Green Tariff (UGT) initiative

The ERC officially issued the "Announcement of the ERC regarding the Criteria for Determining Utility Green Tariff ("UGT") B.E: 2566" in 2023 to promote the use of clean energy in the industrial sector and attract foreign investment. UGT is an electricity-pricing mechanism tailored to meeting the demands of business and industrial clients seeking environmentally friendly energy sources such as solar, wind and hydropower in order to comply with green energy policies and international trade requirements such as CBAM. The three offtakers (EGAT, MEA, PEA) procure green electricity and offer it to customers at UGT rates, ensuring that their energy consumption originates from clean sources. There are two rates, UGT1 and UGT2. Currently, the tariff unit is set at an average price of 4.55 baht per unit.

**Box 4. › Utility Green Tariff programme in Thailand**

Two types of utility green tariffs are available in Thailand:

1. **UGT1 (unspecified source):** UGT1 involves procuring and claiming RECs from existing power plants without specifying the source. Utilities collect purchase orders starting at 100 kWh and procure RECs to match total orders. The term is short (0-1 year) and users pay a premium for RECs in addition to their normal electricity bill. This provides retail power consumers with access to green electricity while maintaining a uniform tariff structure.
2. **UGT2 (specified source):** UGT2 targets large-scale energy consumers who want to increase renewable energy (RE) in the power system by supporting the development of new RE power plants. Utilities manage contracts under the sleeved PPA principle to match electricity and RECs from selected portfolios with user demand, with contract terms of 10-25 years. This tariff structure differs from uniform tariffs due to varying electricity generation durations and costs, reflecting the Ramsey pricing principle.

## Market and contractual arrangements

### Dispatch and system operations

EGAT holds a system operator licence, overseeing the transmission system and operating the national control centre. It follows the system operation guidelines for regulating power dispatch orders as outlined in the Notification on Power Dispatching Framework for Electricity System Operation Licensees B.E. 2564 (ERC, 2021). EGAT dispatches power plants in the following order:

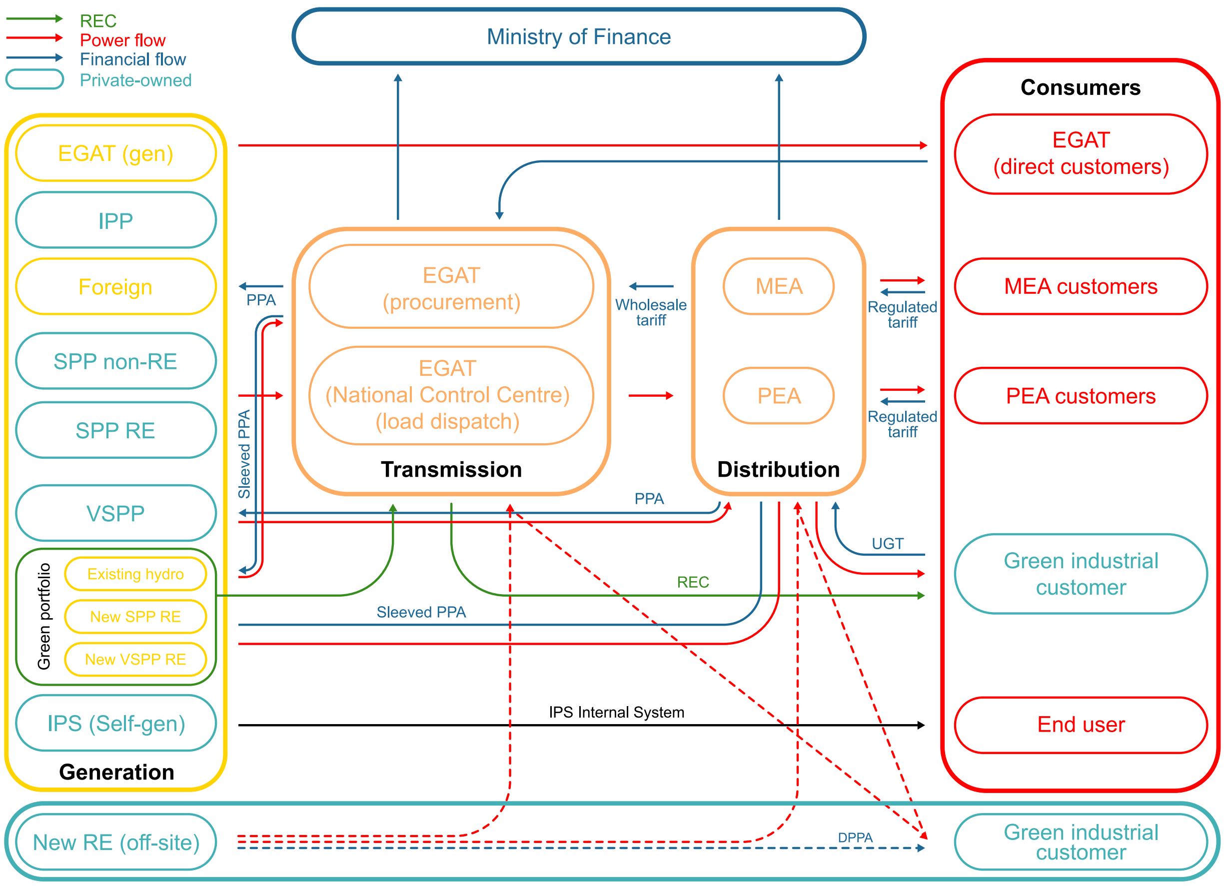
- **Must run:** Power plants in this category are critical to upholding the power system's security and are dispatched first. Failure to operate these plants could lead to potential power outages.
- **Must take:** Must-take power plants are dispatched to meet contractual (minimum offtake) commitments specified in PPAs with EGAT. These power plants include all IPPs (fully dispatchable) and SPPs (firm and non-firm). Under SPP firm contracts, EGAT is obligated to purchase electricity at a minimum of 80 percent of the contracted capacity from these plants. Failure to operate these power plants would result in an obligation to pay for purchased electricity or minimum fuel supply without receiving electricity generation. Consequently, these power plants must remain operational to avoid significant financial losses. On the other hand, non-firm contracts typically involve non-dispatchable arrangements, meaning that EGAT must purchase all the energy produced but can decline to purchase during emergency events affecting system security.

- **Merit order:** EGAT dispatch power plants in this category based on the marginal costs to optimise electricity expenses, including both EGAT and IPP power plants. Dispatching within the merit order group considers the remaining capacity after power plants in the first and second category have been dispatched.

Minimum-take obligations compel EGAT to purchase the contracted volume during peak consumption hours, with corresponding obligations during off-peak hours. Enforcing these obligations during off-peak periods can result in unnecessary costs and limit the acquisition of electricity from VREs, potentially leading to uneconomic curtailment (IEA, 2021). The contractually agreed offtake volumes make it costly to reduce gas power during periods of low demand and may result in an otherwise uneconomical incentive to curtail low-cost renewables. Relaxing contractual offtake obligations from gas plants and accelerating the deployment of renewables would yield fuel cost savings and support Thailand's energy security and affordability objectives.

**RECOMMENDATION – reduce minimum purchase obligations during VRE generation hours.** Under Thailand's single-buyer model, minimum purchasing obligations for thermal power can lead to inflexibility and unnecessary costs, especially during off-peak periods when surplus renewable energy such as solar is generated. To address this, the minimum purchase obligations could be reduced during daylight hours when solar power production is high. This adjustment would lower system costs, reduce uneconomic curtailment of low-cost renewables and facilitate the integration of a larger share of variable renewable energy into Thailand's power system. Meanwhile, the gas fleet could ramp production up again after daylight hours when solar production falls to zero.

**Figure 6. › Thailand's electricity market**




## Electricity procurement and contractual arrangements

EGAT primarily procures electricity from three main sources: IPP, SPP and foreign (see Figure 6). IPP projects are remunerated according to a two-pronged tariff structure:

- **An availability payment (AP)** covers capital and fixed costs, including power plant construction, operating and maintenance expenses and grid connection costs. EGAT pays power plants a readiness fee to ensure their availability to generate electricity as required, regardless of their actual output. EGAT is obligated to make these payments according to the terms set out in the PPAs.
- **An energy payment (EP)** covers the fuel costs for electricity generation incurred by power plants. The EP is based on the guaranteed efficiency of electricity generation, as specified in the PPA. When EGAT dispatches, power plants receive an EP. If more fuel is used than guaranteed, the owner of the power plant bears the burden of this excess fuel usage.

For SPP projects with a contracted power generation capacity of up to 90 MW, contracts fall into two main categories: firm (baseload PPA) and non-firm (closer to a pay-as-produced PPA). For the SPP firm (cogeneration) contract, the costs and remuneration structure of SPP projects resemble those of IPPs:

- **A capacity payment (CP)**, similar to the AP for IPPs, covers the investment costs associated with plant construction, operating expenses and maintenance costs.
- **An energy payment (EP)**, similar to the EP for IPPs, covers the fuel costs for electricity generation and the operational costs of the power plant. Firm SPP power plants with contract extensions receive only the EP cost, excluding the CP cost. This is because it is assumed that these power producers have already fully cov-

ered the capital expenses of the power plant. The contract term is usually 20-25 years.

SPP non-firm contracts (RE) receive only the EP with no dispatch conditions. These non-firm SPPs are typically non-dispatchable, meaning that EGAT will purchase all the energy they produce up to the contracted capacity set out in the PPA. Producers are not penalised when production falls below the contracted capacity. This arrangement allows SPPs with non-firm contracts to recover their capital costs by ensuring consistent sales of their produced electricity. However, EGAT has the option of declining purchases when system issues arise and is not obliged to compensate producers when it does. These contracts have a duration of five years and are renewed upon expiry (Krungsri, 2021).

EGAT has two types of agreements in place to regulate its cross-border electricity trade with Laos and Malaysia: 1) the exchange of non-firm electricity through grid-to-grid arrangements at 115 kV, with prices based on the short-run marginal costs of the exporting country. Renewed annually, these agreements include projects such as Nam Ngum 1, Nam Leuk, Nam Theun 2, Se San 1, Se San 2 and Huay Lamphun. 2) A PPA between EGAT and (Laotian) IPPs, categorised by power plant type and fuel. EGAT pays only the EP for power from hydroelectric plants, reflecting construction costs, with rates varying for peak and off-peak periods. For power from coal-fired plants, EGAT pays both the AP and EP, similar to domestic IPPs. EGAT's purchase agreements with Malaysia are on a non-firm basis, with monthly price notifications and daily confirmations. The power is transmitted through a high-voltage direct-current (HVDC) system. EGAT receives a wheeling charge for transit cross-border power flows between Laos and Malaysia or Singapore.

The AP has been widely discussed as a significant factor affecting electricity prices. Whether the electricity is supplied to the grid or not, the AP/CP must be paid from the commercial operation date. It accounts for about 16 percent of total electricity prices and is embedded in electricity bills at a unit rate of 0.7660 baht. Other main factors influencing electricity prices include the cost of electricity generation, which accounts for 57.45 percent of electricity prices, transmission and distribution (T&D) costs (15.74 percent) and policy expenses (3.42 percent). There is also an additional expense arising from EGAT's debt service obligations, which accounts for five percent of the electricity rate (ERC, 2023). The fixed nature of the AP/CP payments, regardless of electricity supply, may lead to higher electricity prices when demand is lower than projected.

MEA and PEA award VSPP contracts that are available to electricity producers with a power generation capacity of up to 10.0 MW. Like SPPs, VSPPs have been central in Thailand's VRE uptake. Since 2007, the MEA and PEA have introduced incentive programmes, including Adder and FiT schemes, to encourage small-scale renewables deployment (see Policy instruments for VREs" section).

***Fuel supply contracts***

The fuel supply contracts that are in place in Thailand are defined by their take-or-pay obligations and as such have a significant bearing on unit commitment and dispatch decisions. Thailand's gas-fired generation fleet, which largely consists of combined-cycle gas turbines, has significant technical flexibility to accommodate VRE output (minimum load, ramp rates and startup time). Fuel supply contracts dictate minimum offtake requirements in PPAs that constrain the operational flexibility of the gas fleet (IEA, 2023). Reforming contractual obligations to place greater emphasis on flexibility provisions from the existing fossil fuel fleet should be at the centre of Thailand's transition to renewables.

Thailand sources its gas from three primary suppliers: piped gas from national fields, imports from Myanmar, and LNG imports. Gas contracts, including those between PTT and IPPs, adhere to take-or-pay commitments laid down in the master gas sale agreement, often with daily offtake volumes that limit flexibility. Additionally, EGAT's gas supply contracts impose take-or-pay obligations and inhibit the utilisation of potentially more efficient and cost-effective resources, leading to unnecessary increases in operational costs. This inflexibility restricts the economic dispatch of power plants, especially during periods of low demand and high VRE availability, thus reducing the system's ability to flexibly adjust to varying renewable generation.

**RECOMMENDATION – shift gas offtake risk to enhance flexibility.** Thailand's gas supply contracts, including those with PTT and IPPs, impose rigid take-or-pay obligations that limit resource flexibility and increase operational costs. To address this, the observation periods for the take obligation could be extended and the minimum daily take-or-pay contractual volume reduced – during the next contract review. This approach, which could involve EGAT paying a higher margin to PTT for assuming this risk, would improve the flexibility of power plant dispatch, especially during periods of low demand and high VRE availability. PTT would then manage upstream contracts to mitigate risks effectively.

**Box 5. › Regulatory impact on contractual flexibility in Thailand's gas market**

- Thailand's natural gas sector is characterised by a vertically integrated monopoly that is controlled by a single conglomerate led by PTT Public Company Limited, which is a partially privatised state-owned energy corporation. Since 2011, the landscape of natural gas markets in Thailand has evolved significantly with the introduction of LNG imports. This has given rise to opportunities for market liberalisation and challenged PTT's historical dominance.
- Thailand is currently in phase 2 of its natural gas liberalisation plan. While the plan for liberalising the gas business structure in both phases 2 and 3 has been announced, the market design, especially for phase 3, remains unclear.
- The introduction of LNG imports has implications for contractual constraints within the power sector. Prior to the implementation of TPA regulations by the ERC, PTT secured long-term gas supply agreements without exit clauses, which limited competition in the gas supply sector. This had repercussions for the power sector, where long-term commitments in gas contracts mirrored the inflexible terms of electricity contracts (Dodge, 2020).
- The interplay extends to electricity contracts, which often necessitate parallel long-term commitments in gas contracts to ensure stability and supply continuity. However, this poses a challenge due to the inflexible operational terms inherent to long-term PPAs with IPPs.
- Despite evolving demand and supply dynamics, these contractual terms have remained rigid, contributing to ongoing system inflexibility. Moreover, PTT continues to maintain a monopoly in the natural gas market, further entrenching the challenges faced in both the gas and power sectors

Electricity tariffs in Thailand are structured according to wholesale and retail categories. MEA and PEA, the distribution utilities, procure electricity from EGAT at wholesale prices and then sell it to end users at retail rates. The retail electricity tariff is based on a uniform tariff system such that users within a consumer category pay the same electricity rate irrespective of their location in the country. There are two options for electricity charges: 1) uniform rates and 2) time-of-use rates (TOU), with varying monthly service fees. Currently, Thailand has eight distinct regulated retail tariff schedules, each catering to different customer segments: residential, small-medium-large businesses, specific business service, non-profit organisation, water pumping for agricultural purposes, and temporary service. Additionally, the structure of retail electricity tariffs may vary according to consumption levels and voltage requirements. Certain user groups benefit from cross-subsidisation policies facilitated by the Power Development Fund (PDF), ensuring that retail tariffs remain equal across the country for a given customer class (i.e. MEA and PEA tariffs are the same). Subsidies and government intervention mean that current electricity rates do not accurately reflect true costs, however.

Retail electricity tariffs in Thailand consist of three main components: 1) the base tariff, 2) a fuel adjustment charge (Ft) and 3) a value-added tax of seven percent.

- **The base tariff** is a predetermined and fixed rate that covers power plant construction (0.7660 baht per unit), transmission (0.24 baht per unit) and distribution (0.51 baht per unit), and policy expenses (0.1629 baht per unit). It is structured to meet the utility revenue requirements and appropriate profit margins. This tariff also includes fuel costs from EGAT, procurement costs from IPPs, SPPs and VSPPs, and imports at 2.7381 baht per unit (ERC, 2023). The base tariff is updated every three to five years. The EP and import costs are reflected in fuel costs, while the AP, CP and EGAT (internal PPA) costs are reflected in power plant construction costs.
- **The fuel adjustment charge (Ft)** is a mechanism that adjusts electricity tariffs based on changes in fuel costs compared to the initial estimate in the base tariff. It also considers any deviation of fuel costs from the ex-ante procurement of IPPs, SPPs and VSPPs, along with policy expenses. Ft is updated every four months to reflect fluctuations in fossil fuel prices, which may impact customers' bills.

The fluctuation in fossil prices reflected in Ft contributes to the change in electricity prices. Consequently, the average electricity price increased to 4.85 baht per unit in 2022-2023, a 16 percent rise from 4.18 baht per unit in 2022 (Kasikorn, 2022). To address this, the government implemented measures to cap electricity prices at not higher than five baht per unit for general customers and 3.99 baht per unit for specific groups (households using less than 300 units of electricity) (TDRI, 2023). However, there is concern that reduced financial support and currency depreciation would increase the tariff. These factors impose a certain level of uncertainty on electricity price developments over the coming years.

Utility revenues are regulated on the basis of the rate-of-return regulation, which is integrated into the base tariff. This revenue includes EGAT's generation and transmission costs, the distribution and retail expansion costs of MEA and PEA, operation and maintenance (O&M) costs and the return on invested capital (ROIC) of all three utilities. Calculation of ROIC depends on the type of asset and investment and is divided into three categories:

- **Normal investment assets** (related to electricity production, transmission and distribution) – ROIC ranges from 4.7 percent to 5.7 percent (NEPC, 2015).
- **Specific-purpose investments** such as underground power line projects or railway projects – ROIC is generally lower than in the first case and varies according to the project.
- **Supportive investments unrelated to the primary business** for which no returns are provided.

### Market integration VREs

There are two offtake agreements for renewable energy in Thailand: **non-firm (pay-as-produced) and partial firm. Non-firm agreements** involve running power plants at full capacity based on generator and energy source readiness. They apply to biogas, wind and solar energy (SPPs and VSPPs) and mitigate the risk of a production mismatch, thus supporting the bankability of projects. However, non-firm arrangements give offtakers the flexibility to decline purchasing, including when system issues arise such as overvoltage or transmission congestion (ERC, 2022), exposing VRE producers to volume risk. This highlights the difference between non-firm arrangements and traditional pay-as-produced PPAs, the former not obliging the offtaker to purchase all renewable energy output.

It is important to ensure that VRE producers with non-firm contracts are not curtailed to accommodate generation from other sources such as coal or gas. Curtailing renewables to make room for fossil fuel generation is economically inefficient given the high marginal costs of thermal power plants. Additionally, the environmental impact of coal and gas generation should be considered when integrating VREs in Thailand. Improving the accuracy of renewable energy forecasting to take specific local contexts into account can help optimise electricity generation capacity and voltage control methods, thereby enhancing the stability of the system (IEA, 2021). A mechanism for VRE curtailment has not yet been introduced in Thailand. Determining compensation for curtailed electricity is crucial, considering the potential revenue loss; however, curtailment is essential for grid stability. If introduced, compensation payments for curtailed renewable energy must consider factors such as production capacity or natural reference values. Establishing an allowable renewable energy curtailment quantity can grant flexibility to providers, while penalties should be stipulated for non-compliance (ERC, 2021).

The latest FiT programme introduces the **SPP partial firm** mode for ground-mounted solar plus BESS to enhance grid stability and VRE integration. Under this contract, there is an obligation to purchase electricity during specified periods.

- Between 9:00 AM and 4:00 PM, electricity production for both grid supply and purchase must be at 100 percent of the contracted volume.
- From 6:01 PM to 6:00 AM, readiness to supply electricity at 60 percent of the contracted volume for a two-hour duration is required, with total purchased electricity and maximum dispatch not exceeding 60 percent of the contracted volume.
- From 6:01 AM to 9:00 AM and from 4:01 PM to 6:00 PM, electricity production and purchase must not exceed 100 percent of the contracted volume.

The challenge posed by the SPP partial firm mode lies in ensuring grid stability during transition periods, especially from 6:00 AM to 9:00 AM and 4:01 PM to 6:00 PM. Balancing electricity supply and demand without exceeding contracted volumes can be complex, particularly due to fluctuations in solar power. Effective forecasting and management, including optimised use of BESS, are essential for success.

# Recommendations

### Pillar 1 › Provide long-term investment certainty for VREs

- **Enhance the centralised procurement process for renewable energy.** Thailand's electricity market operates under a single-buyer structure in which major renewable energy projects rely heavily on government policies for power procurement. Therefore, it is crucial for Thailand to align centralised procurement processes with a net-zero trajectory and introduce a solar booster programme with an annual installation target of 5 GW (Energy Research Institute, Agora Energiewende, NewClimate Institute 2022). This initiative, supported by clear targets in the PDP and a committed implementation strategy, would attract the necessary investments, including green financing at preferential rates. Such financing would benefit the government through lower tariffs due to reduced financing costs and provide assurance regarding the technical challenges of integrating renewable energy into the system.
- **Implement a competitive procurement framework for large-scale projects.** High investor readiness and interest in previous renewable energy tender rounds underscore the potential for Thailand to scale its procurement pipeline and reduce costs with a competitive selection mechanism. Reverse auctions could be introduced to select least-cost bids and award these with a long-term PPA at their bid price.
- **Ensure capacity alignment and transparency in renewable energy procurements.** Implement a competitive procurement framework for large-scale projects, focusing on capacity alignment and transparency. Leveraging Thailand's high investor readiness and the large pool of potential bidders and transitioning to competitive auctions could reduce VRE contract costs. Transparent communication about new auction rounds, including application and selection processes, is essential to boost investor confidence. Additionally, the policymaker, the regulator and the MEA, PEA and EGAT could enhance coordination to ensure that VRE capacity planning is integrated into the procurement schedule and supported by necessary grid investments.
- **Accelerate the implementation of third-party grid access:** Implementing the third-party access (TPA) codes by major utilities is crucial for fostering market confidence and facilitating direct engagement in renewable energy procurement. In alignment with the TPA framework, promptly establish an appropriate wheeling charge and set network system service fees to balance enhanced network access while maintaining the country's overall energy costs.
- **Regular review of solar target purchase rate:** Implement periodic reviews of the surplus electricity purchase rate, currently set at 2.20 baht per kWh under the net-billing scheme. This review process should reflect the overall value of solar provided by solar injections, considering factors such as reduced operational costs and avoided grid investments. It should ensure that the purchase rate remains fair and reflective of market conditions, promoting growth in the solar energy sector while avoiding any undue financial burden on ratepayers.
- **Streamline permitting processes:** Simplify and streamline permitting processes to reduce the lead time and transaction costs associated with renewable energy projects. Establish a centralised one-stop service for permitting to facilitate efficient project development and approval.

## Pillar 2 › Enhance system flexibility to integrate variable renewables into the system at the least cost

*Current power system*

- **Reduce minimum purchase obligations during VRE generation:** Under Thailand's single-buyer model, purchasing of thermal power at excessively high minimum volumes has led to inflexibility and resulted in unnecessary costs, particularly during off-peak periods. The electricity procurement obligations should be reduced during daylight hours when solar power production is high. This would lower system costs and enable greater shares of variable supply to be integrated into Thailand's power system.
- **Renegotiate existing contracts for greater flexibility:** Review EGAT's current take-or-pay fuel supply contracts to reduce minimum offtake commitments in PPAs such that VREs can be utilised at maximum output without additional payments to gas-fired power plants. This may involve adopting a more diversified procurement strategy with a combination of short-, medium- and long-term products.
- **Harmonise grid codes:** Synergise grid codes among EGAT, MEA and PEA to accommodate the growing number of VREs, including ESS, on the demand side (energy management, demand response).
  1 **Update existing grid codes:** Include provisions for accommodating VRE generation, such as defining criteria for assisting the system beyond over-frequency droop or automatic power curtailment.
  2 **Establish guidelines for VRE curtailments:** Include mechanisms for determining compensation for curtailed electricity and penalties for non-compliance.

*Future power system*

- **Introduce flexibility in new/redesigned PPAs for conventional assets:** Tender new/redesigned PPAs with more flexible terms, including higher ramp rates, lower minimum generation levels and shorter start-up times to allow for greater operational flexibility.
- **Integrate new flexibility sources:** Employ new flexibility sources – integrate BESS, demand-side flexibility (peak demand shift from daytime to nighttime) and pump storage hydropower (PSH)
- **Expand grid transmission infrastructure:** Upgrade and expand grid transmission infrastructure to accommodate the scaling up of VRE.
- **Implement transparent pricing mechanisms:** Design pricing mechanisms such as time-of-use (ToU) tariffs or real-time pricing (RTP) that value and unlock demand-side flexibility. This involves establishing clear pricing signals that reflect the spatial and temporal variations in electricity demand and supply, enabling market participants to respond efficiently to changing conditions.

## Pillar 3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs

- **Dynamic planning with probabilistic criteria:** Incorporate loss of load expectation (LOLE) and expected energy not served (EENS) metrics into energy planning frameworks to dynamically evaluate and adapt reserve margin requirements. Currently, Thailand maintains a reserve margin of approximately 36 percent, exceeding the recommended threshold of 15 percent of peak power demand. This surplus poses challenges for scaling up RE integration within the system. Adjusting reserve margin targets through LOLE analysis allows for a more responsive approach to accommodating the growing share of RE while ensuring system reliability.

► **Halt the construction of fossil baseload power plants:** Cease the construction of new large-scale power plants to prevent further surplus in electricity reserves. Prioritise the optimisation of existing infrastructure and investment in flexible generation and storage technologies, including dispatchable and variable renewables, to meet future energy needs.

► **Optimise BESS for grid integration:** Clearly define and strategically position BESS within the power system to enhance grid flexibility, support RE integration and improve overall system reliability. Align BESS deployment with the PDP to ensure optimal utilisation and contribution to system objectives.

### Pillar 4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets

► **Encourage repurposing and retrofitting:** Develop policies that incentivise the repurposing or retrofitting of existing thermal power plants in Thailand to provide grid flexibility services. This approach can help reduce emissions while preserving existing infrastructure and minimising economic disruption.

► **Introduce an emissions-intensity factor into dispatch operations** to ensure cleaner generation sources are utilised most. This can be done by accelerating earlier efforts to introduce an ETS or via new dispatch regulations.

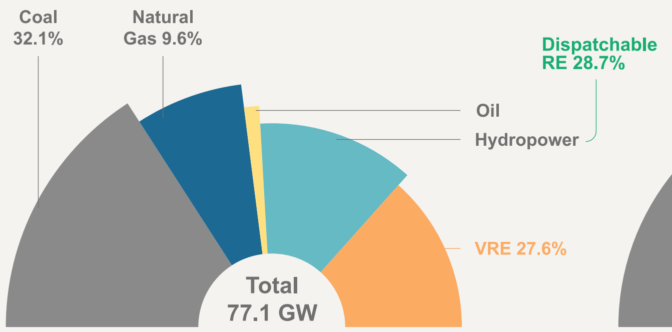
### Pillar 5 › Ensure affordable electricity for consumers while maintaining the sector's financial sustainability

► **Reform the electricity tariff structure:** Adjust the electricity tariff structure to reflect both fixed and variable costs. Fixed costs, such as power plant construction, would be shared by all grid-connected users, while variable costs such as fuel expenses would be determined by a consumer's choice of supplier.

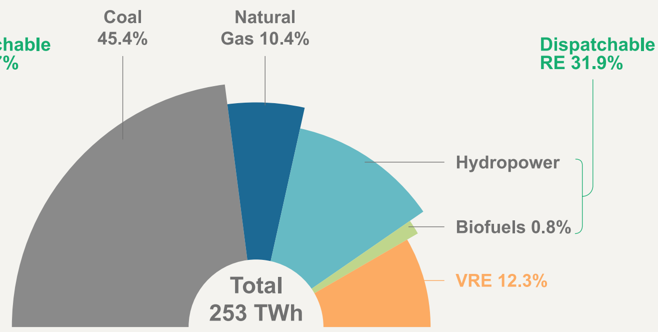
**1 Review and reform the availability and capacity payment mechanisms:** EGAT pays an availability payment to power plants as a readiness fee to ensure their availability for electricity generation. The fixed nature of AP/CP payments, regardless of electricity supply, can inflate electricity prices to cover power plant readiness costs. Exploring options to align AP structures with actual electricity generation can increase cost effectiveness and ensure a fair pricing mechanism for customers.

**2 Revise the fuel adjustment charge (Ft) formula:** The ERC has an opportunity to revise the automatic tariff adjustment mechanism formula for fuel cost recovery. Currently, the calculation method relies on forecasting energy demand and estimating fuel prices averaged over a four-month period. A revised formula could base adjustments on the actual cost of purchased electricity over the preceding four months. This will ensure a more accurate reflection of market dynamics and enhance transparency in tariff adjustments.

# 5 Viet Nam – an unbundled single-buyer system




**Installed generation capacity in 2022**




**Electricity generation in 2022**

**0.49**

**Grid emissions factor ($tCO_2e/MWh$)**

Source: EDGAR, 2023; IEA; 2021, SIPET, n.d.; ; Statista, 2024; VEPG, 2023.

### Table 6. › Overview of key findings for Viet Nam*

| | Enabler | Barrier |
|---|---|---|
| **Investment certainty for variable renewables** | • Conducive environment for RE investments without local content requirements<br>• Attractive feed-in tariffs (FiTs) for solar and wind<br>• Open to foreign investment with up to 100% ownership in power projects | • Delay in finalising implementation plan for Power Development Plan 8 (PDP8)<br>• Insufficient grid capacity to handle output from numerous RE projects<br>• High initial investment costs for solar and wind power plants |
| **System flexibility and VRE integration** | • Favourable incentive frameworks including tax incentives and duty exemptions<br>• Priority dispatch for VRE power plants (not formalised)<br>• Plans to develop a new wholesale market with short-run value signals | • Lack of compensation mechanisms for ancillary services<br>• Regulatory inconsistencies in participation of VRE units in the wholesale energy market<br>• Insufficient grid infrastructure and operational flexibility |

| | Enabler | Barrier |
|---|---|---|
| **System adequacy** | • High potential for VRE deployment supported by National Power Development Plan 8 (PDP8)<br>• Strategic augmentation and reinforcement of the 500 kV power transmission system | • Transmission congestion and inadequate system-wide planning<br>• Balancing challenges with growing emphasis on solar power integration |
| **Phase-out of carbon-intensive assets** | • Commitment to reduce coal-fired generation project pipeline<br>• PDP8 aims for a significant reduction in GHG emissions by 2030 and 2050 | • Substantial new coal capacity expected to come online<br>• Existing coal plants to remain operational beyond 2030 |
| **Affordability** | • Competitive VRE costs due to the absence of local content requirements<br>• Direct subsidies available for low-income households | • Retail tariffs not reflective of generation costs<br>• Significant financial losses for EVN, impacting its ability to fulfil long-term purchasing commitments and drive network investments<br>• High perceived risks due to regulatory uncertainties |

*recommendations are provided at the end of the chapter

Power system transformation in Viet Nam has been intricately linked to the country's history. In 1976 the reunion of North and South Viet Nam saw the government inherit two southern power utilities. Subsequently, three separate vertically integrated state-owned utilities supplied electricity across the country with limited private sector participation in informal distribution and retail markets. However, limited regulatory and institutional capacity meant that the financial viability of the three utilities was sub-optimal. Transmission constraints between the two regions created an imbalance, with surplus installed generation capacity in the north and inadequate supply in the south. Viet Nam's power market has since undergone significant reforms to promote unbundling and create a competitive market environment (See Figure 1Figure 7). Currently, the country has an unbundled single-buyer system with a cost-based pool market for power generators. This market arrangement is in the process of transitioning towards a competitive price-based pool market, which aims to introduce greater flexibility and efficiency in dispatch.

Broader legislative and policy reform such as the Doi Moi reforms launched in 1986 and a new constitution introduced in 1992 paved the way for market reform to sustain the rapidly growing economy. This transformative period saw a significant rise in electricity demand, reflecting the needs of an expanding industrial sector and a burgeoning population. However, utilities were incapable of meeting this surging demand due to financial and infrastructural constraints, prompting the government to seek investment from independent power producers (IPPs). In 1994, the government opened the generation segment to IPPs and the first sizeable coal IPPs were commissioned in 1996. However, a lack of competitive bidding and the government's reluctance to allow higher tariffs for new power generation hampered private sector participation. As a result, the state-owned PetroVietnam and Vinacomin were mandated to construct new coal- and gas-fired power plants.

**Figure 7. › Viet Nam power sector reform**

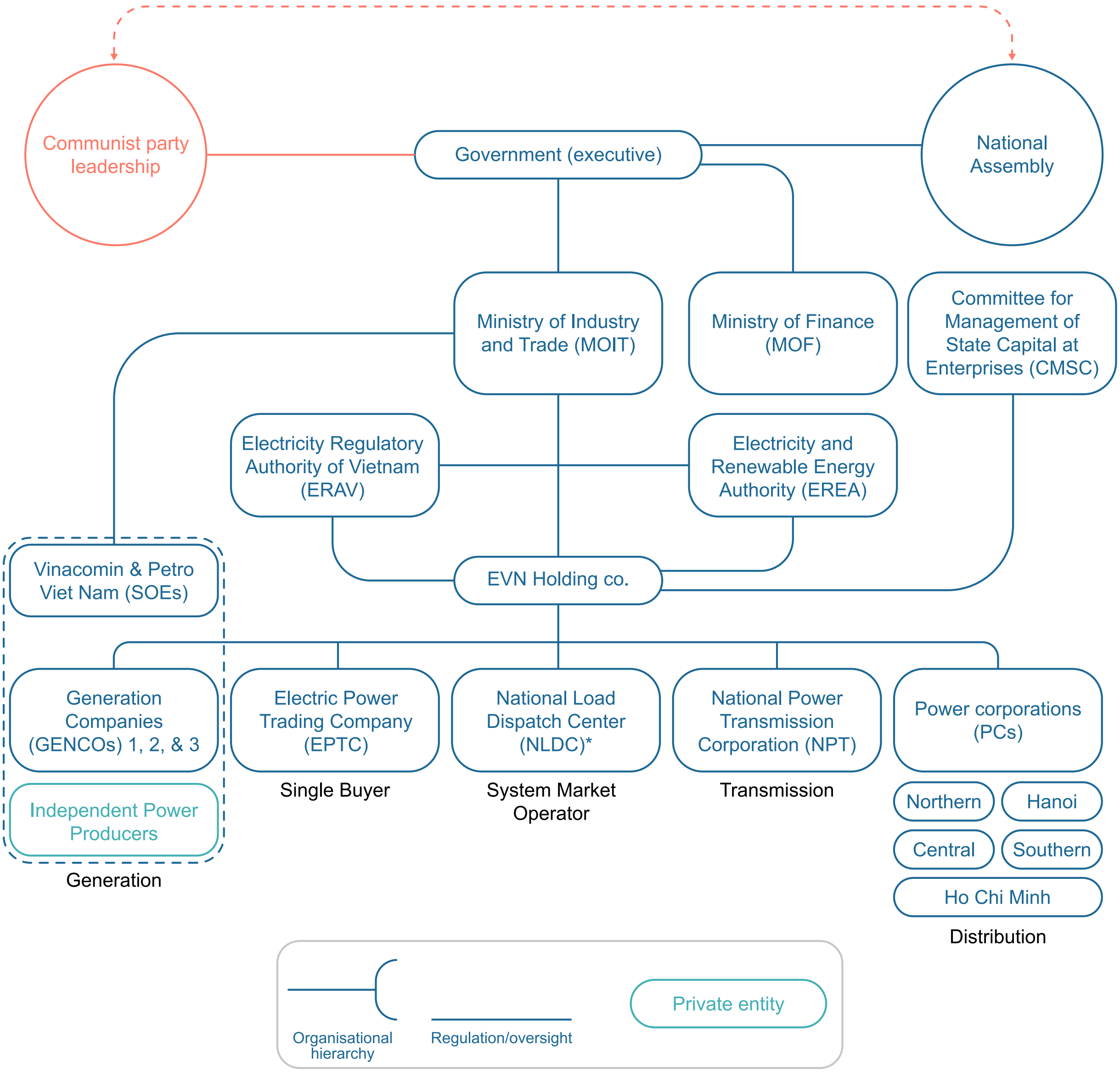
| Power sector reform in Viet Nam (1970-2023) | |
|---|---|
| | **Restructuring**<br>1994: Establishment of National Load Center<br>1995: Integration of 3 state-owned enterprises to form Electricity Viet Nam (EVN)<br>2003: EVN partial unbundling<br>2005: Partial privatisation of one EVN discom<br>2007: Approval of EVN partial divestiture plan<br>2010: LDUs taken over by EVN<br>2006: EVN corporatised<br>2008: EVN subsidiary, Electricity Power Trading Company (EPTC) established<br>2010-16: Partial divestiture of generation (1.9 GW)<br>2010: 5 EVN power corporations established from distribution companies<br>2011: Division of generation assets into 3 generation companies |
| | **Market reform**<br>1994: Introduction of independent power producers<br>2011: Piloting of Viet Nam Competitive Generation Market (VCGM)<br>2012: Full operationalisation of VCGM<br>2016: Piloting of wholesale electricity market<br>2018: VGCM reaches USD 4.6 bn trading volume and 51% of installed capacity |
| | **Legislative and policy reform**<br>1986: Launch of Doi Moi<br>1992: New constitution enables private ownership<br>2001: Constitutional amendment to improve private sector participation and accountability<br>2004: Electricity Law passed<br>2006: 20 year reform roadmap<br>2012: Electricity Law Amendment<br>2013: Reform roadmap updated |

Source: Adapted from Lee & Gerner (2020)

The Electricity Law of 2004 included new provisions for competition, the unbundling of Electricity Viet Nam (EVN) and the establishment of the Electricity Regulatory Authority of Viet Nam (ERAV) (Lee & Gerner, 2020). Initially, the unbundling of EVN was only functional in nature, as operations were segmented into generation, transmission and distribution, while the ownership structures remained under the overarching control of EVN. Subsequent reforms included tariff reform to ensure cost reflectivity, divestiture of generation ownership, corporatisation of EVN as a group and the establishment of the Electricity Power Trading Company (EPTC) as an EVN subsidiary. In January 2009, EVN underwent legal unbundling and ceased to operate as a vertically integrated utility. It was transformed into a holding company and renamed Viet Nam Electricity, though it retained the acronym EVN (Asian Development Bank, 2015).

# Institutional structure

## Figure 8. › Viet Nam's power sector institutions




* In August 2024, the NLDC was transferred to MOIT and became the National Electricity System and Market Operation (NSMO) Company Limited.

10 Since 2017, EVN has been working on making the NLDC a financially independent entity. On 6 June 2023, the Prime Minister directed the MOIT to take control of the NLDC to ensure a stable electricity supply. In response, MOIT proposed two options in a report to the Prime Minister on 14 June: either reconstitute the NLDC as a public non-profit organisation under MOIT or convert it into a state-funded single-member limited liability company under MOIT's management. As such it is envisioned that NLDC will be placed under the direct control of MOIT in the near future.

11 EVN is under MOIT management in terms of policy. At the same time, state-owned enterprises such as EVN are under the financial management of the Commission for the Management of State Capital (CMSC).

Viet Nam operates as a socialist republic and one-party state in which the Communist Party of Viet Nam (CPV) has control over both the state and society. The General Secretary of the CPV both leads the party and holds positions in the Politburo and the Central Military Commission, effectively making them the de facto supreme leader. The President is the head of state, while the Prime Minister is the head of government. The National Assembly is responsible for legislative processes and enacting policies across all sectors, including the electricity sector. The CPV is the only political party in power and has leadership of the state and society. This centralised political structure underscores the significance of the party's influence in shaping regulations and policies related to the electricity sector in Viet Nam.

### Policy and regulation

The Ministry of Industry and Trade (MOIT) serves as a central institution in Viet Nam's power sector, ensuring regulatory oversight, market efficiency and adherence to legal standards. MOIT responsibilities include optimising the operation of the electricity market. This entails formulating and enforcing regulations governing the competitive electricity market, supervising the development and implementation of electricity supply plans and monitoring the electricity supply industry to balance supply and demand. MOIT oversees and collaborates with the Ministry of Finance (MOF) to establish methods for determining electricity generation prices, wholesale prices, transmission prices, system support service prices and fees associated with electricity system operation and market transactions. In consultation with MOF, MOIT approves operation dispatching fees and market transaction management fees. Moreover, it is mandated to scrutinise fixed-term electricity purchase contracts between electricity generating units and purchasing units, as well as fixed-term electricity wholesale purchase contracts, in accordance with government regulations. The ministry is authorised to resolve disputes within the electricity market and inspect compliance with electricity sector laws while addressing any violations in accordance with legal provisions.

In addition to MOIT, the Committee for Management of State Capital at Enterprises (CMSC) plays a significant role in the financial management of state-owned enterprises (SOEs) in the energy sector. The CMSC, through its Department of Energy, develops and implements strategies, plans and programmes related to state capital management in the energy sector, ensuring that enterprises under its purview are efficiently governed and comply with relevant legal and regulatory frameworks. This comprehensive oversight includes appraising investment projects, monitoring and evaluating business performance and implementing modern corporate governance solutions. CMSC's integration into the financial oversight process ensures a robust framework for the financial management and governance of state-owned enterprises in Viet Nam's electricity supply industry.

The Electricity Regulatory Authority of Viet Nam (ERAV) is responsible for market regulation and operational supervision of the competitive power market. Established in 2005, ERAV is also tasked with tariff setting and review. However, ERAV does not carry out its functions independently of the line ministry, MOIT and government, with whom decision-making power lies. Despite having limited independence, ERAV performs at the global average levels in the areas of market entry and tariff setting (Lee & Gerner, 2020).

To complement MOIT and ERAV, the Electricity and Renewable Energy Authority (EREA) was established as a successor to the former General Directorate of Energy in 2017. Subordinate to MOIT, EREA is responsible for managing and regulating the electricity and renewable energy sectors. Specifically, EREA formulates and submits legal documents, national strategies and sectoral plans to MOIT for promulgation. EREA also develops mechanisms and policies for renewable energy development, with the exception of tariff setting and power purchase contracts.

# Market structure

Established in 1994 and incorporated in 2010, EVN subsidiaries comprise the following:

Subsidiaries wholly owned by EVN (100 percent charter capital)
- Power Generation Corporation No. 1 (GENCO 1)
- National Power Transmission Corporation (EVNNPT).
- Northern Power Corporation (EVNNPC),
- Central Power Corporation
- Southern Power Corporation
- Hanoi City Power Corporation
- Ho Chi Minh City Power Corporation
- Thu Duc Thermal Power Company Limited

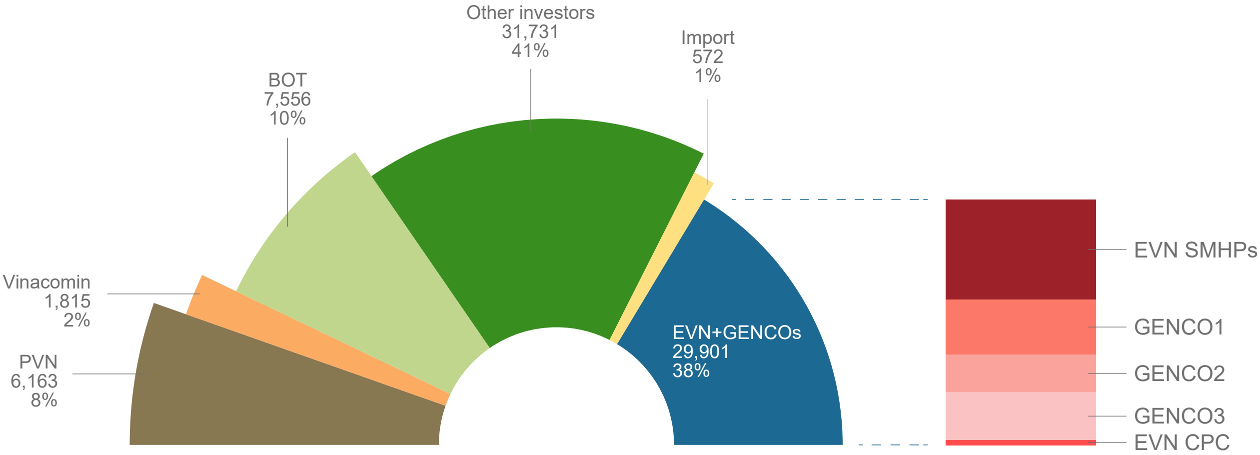
Subsidiaries over 50 percent owned by EVN
- Power Generation Corporation No. 2 (GENCO 2)
- Power Generation Corporation No. 3 (GENCO 3)
- Power Engineering Consulting Joint Stock Corporation No. 1
- Power Engineering Consulting Joint Stock Corporation No. 2
- Power Engineering Consulting Joint Stock Corporation No. 3
- Power Engineering Consulting Joint Stock Corporation No. 4

Subsidiaries in which EVN holds less than 50 percent of the charter capital
- Dong Anh Electrical Equipment Corporation - JSC
- Power Engineering Consulting Joint Stock Corporation No. 3
- Vinh Tan 3 Energy Joint Stock Corporation

### Generation

Viet Nam has made significant strides in its power sector reform journey. Among other things, it has carved out three new generation companies – GENCO 1, 2 and 3 – following the unbundling of EVN's portfolio of power plants. Due to legal unbundling, EVN remains the holding company for GENCOs 1,2 and 3 and as such a key player in the market. EVN also operates strategic and multipurpose hydropower plants (SMHPs). In 2022, EVN power plants (SMHPs and GENCOs 1, 2 and 3) accounted for 38 percent of the national installed generation capacity, with a total capacity of 29 901 MW (EVN, 2023). This is a marked reduction from its 59 percent share of total installed capacity in 2018. EVN's decreased market share reflects Viet Nam's rapid deployment of VREs over 2018-2022 – nearly 17 GW in solar power and 5 GW in wind power – financed largely by private and foreign investors. Overall, private sector and foreign investors now account for more than 50 percent of the country's installed capacity, as shown in Figure 9 (EVN, 2023). Besides EVN and private producers, the SOEs Vinacomin and Petro Viet Nam (PVN) own coal- and gas-fired power plants with total capacities of 1 815 MW and 6 163 MW respectively.

**Figure 9. › Ownership of installed generation capacity in MW**




Source: EVN, 2023.

## Transmission, distribution and retail

Through its legally separated subsidiaries, EVN retains control over the transmission and major distribution networks. Though Viet Nam's electricity transmission network has expanded significantly, a suite of challenges remain. The EVN's National Power Transmission Corporation (EVNNPT) operates an extensive network of 10 467 kilometres of high-capacity 500 kV lines and 18 953 kilometres of the more widespread 220 kV lines. The combined transformer capacity of the EVNNPT network exceeds 120 000 MVA. Notably, EVN has achieved a remarkable milestone with electricity connectivity now extended to all districts, with nearly total coverage of communes and rural households.

The PDP8 envisions a strategic augmentation and reinforcement of the 500 kV power transmission system, focusing on enhancing interconnectivity between central power generation regions and the main demand centres in the south and the Red River Delta in the north. These initiatives are pivotal as they will support the grid's ability to manage the variability and integration of variable renewable energy sources, which is a central goal of Viet Nam's energy policy.

The Northern Power Corporation (EVNNPC), the Central Power Corporation (EVNCPC) and the Southern Power Corporation (EVNSPC) collectively manage extensive portions of the 110 kV lines and transformers, as well as medium- and low-voltage lines, ensuring regional balance and supply security. In 2022, EVNNPC controlled over 9 800 kilometres of 110 kV lines, while EVNCPC and EVNSPC oversaw around 4 162 and 6 072 kilometres respectively. Their responsibility also encompasses a substantial transformer capacity, with EVNSPC accounting for over 10 479 MVA in medium-voltage transformers alone, pointing to a robust network that is able to meet current and future demands.

The National Load Dispatch Center (NLDC) is navigating complex challenges in balancing the grid. With a growing emphasis on solar power integration, NLDC has occasionally curtailed output from hydropower plants to prevent grid overloads. This balancing act will become increasingly complex as more variable renewable energy comes online. The planned transition of NLDC to an independent body under MOIT would establish an independent system operator (ISO). This move is aimed at enhancing the operational independence and efficiency of Viet Nam's power market, ensuring that grid and market operations are managed without commercial biases. The ISO will play a critical role in enhancing transparency and fairness in market operations, elements that are crucial when it comes to building investor confidence and attracting investment at competitive costs. A transparent and fair market reduces the risk premiums investors require, which can lower the cost of capital for new energy projects, ultimately benefiting end users through lower electricity prices.

Investment remains a key issue, with MOIT estimating that approximately 14.9 billion US dollars will be needed to enhance the grid by 2030. These investments will likely focus on upgrading the existing 500 kV systems and introducing smart grid technology to modernise the network. The introduction of such advanced technology is essential not only for grid stability but also for the adoption of variable renewable energies. Furthermore, the government is signalling a shift towards privatisation in transmission and sub-stations, which could attract international investment and drive growth within the sector. This shift, guided by the Public Private Partnership (PPP) legislation, is anticipated to bolster grid improvements and power expansion, thereby facilitating the seamless integration of renewables.

The Electric Power Trading Company (EPTC) is an EVN subsidiary and the single buyer of electricity. The EPTC signs power purchase agreements with generators that are typically designed to reflect operation and ownership costs but provide limited incentive for generators to improve efficiency and reduce costs. NLDC is the market and system operator for the wholesale market and transmission network. In a proposal to the Prime Minister in June 2023, MOIT proposed that NLDC be separated from EVN, though this has yet to be implemented. With growing private sector participation, such a move would support Viet Nam's development of transparent and efficient power markets. The five distribution companies – Northern, Central, Southern, Hanoi and Ho Chi Minh City Corporations – are wholly owned by EVN. They were established after 11 distribution companies and local distribution utilities (LDUs) consolidated in preparation for market competition in the wholesale and retail segments. The retail sector is gradually opening up and envisions participation from non-EVN entities, although it is still in the early stages of competition. It is anticipated that a trial system for the direct purchase and sale of electricity between power producers and consumers will be established by 2025. Additionally, the functions of electricity distribution, which is inherently monopolistic, and electricity retail, which is intrinsically competitive, are set to be delineated. This restructuring is aimed at enhancing both the transparency and efficiency of the power sector.

## Investment regulations and market openness

### Foreign ownership

Viet Nam's power sector showcases a dynamic interplay between liberalisation and strategic regulation in foreign investment. Governed by Resolution 55 issued by the Politburo in 2019, Viet Nam aims to attract 50 billion US dollars in foreign investment by 2030, highlighting its ambition to bolster the economy through substantial infrastructure projects, particularly in renewable energy sources such as wind and solar. This commitment is further supported by the revised Law on Investment and the Public Private Partnership Law of 2020, which are designed to foster an investment-friendly environment conducive to high-quality, technologically advanced and environmentally sustainable projects.

In the renewable energy sector, Viet Nam boasts a remarkably open regime for foreign investment, allowing up to 100 percent foreign ownership in power projects. This liberal approach underpins Viet Nam's strategy of accelerating the development of renewable energy and meeting its expansion and sustainability objectives whilst minimising ownership limitations. Unlike other sectors in which foreign ownership may be capped to safeguard national security interests – as detailed in Decree 31/2021/ND-CP which imposes restrictions and stringent market access conditions in certain areas – the renewable energy sector benefits from a more relaxed framework. This facilitates the rapid scale-up of capacity in critical areas such as wind and solar energy, reflecting the country's strategic use of foreign direct investment (FDI) to drive growth in its energy sector. However, this is applicable only when a foreign company establishes a company in Viet Nam. FDI entities and representative offices of foreign companies can only own up to 49 percent of a company's shares.

### Local content requirements

Viet Nam has created a conducive environment for renewable energy investments without imposing local content requirements, which typically mandate a certain percentage of locally sourced materials or labour for projects. However, Vietnamese employment law stipulates that foreign employees may only be hired if no qualified local candidates are available, further supporting the local workforce while keeping avenues open to international expertise. This balanced approach helps maintain competitive costs while promoting foreign investment and technological advancement in Viet Nam's renewable energy sector. Since 2019, the country has ranked among the top 40 globally in terms of its appeal for renewable energy investments.

### Barriers to market entry

Several significant barriers impede the growth of the renewable energy sector and access to renewable sources for businesses. The delay in finalising the detailed implementation plan for the recently adopted Power Development Plan 8 (PDP 8) created uncertainties, making it difficult for new renewable energy projects to receive greenfield approvals. However, the implementation plan for PDP 8 was eventually released, as stated in the Prime Minister's Decision No. 262/QD-TTg, which formally approves the plan for national power development from 2021 to 2030, with a vision towards 2050. Wind power capacity is envisaged to reach 28 GW by 2030 – a more than 20 GW increase compared to current levels – with six GW coming from offshore wind parks. By 2050, the offshore wind power fleet is to increase to 70 GW. Furthermore, the government aims for nearly 190 GW of rooftop solar capacity to be installed by mid-century. Despite these ambitious targets, the fossil power fleet is also set to grow in size with nearly 30 GW of additional gas power plants and four GW of coal power to be added by 2030.

A major challenge is the national grid's capacity, which is often insufficient to handle the output from numerous renewable energy projects and thus leads to operational constraints. EVN is mandated to invest to keep up with large-scale power system expansion but is constrained in its ability to recover transmission and distribution investments by the cap on retail tariff adjustment. Although the state has proposed that the exclusivity on grid transmission development be lifted in order to encourage private sector participation, significant advancements are still required to enhance grid infrastructure. Additionally, the process of obtaining the necessary permits often involves delays, especially during the integration of projects into the power development plan and site clearance. The Electricity Law is currently under revision and is expected to include an article on lifting exclusivity on grid transmission.

Furthermore, power purchase agreements (PPAs) in Viet Nam are typically in statutory standard form, which does not offer adequate protective clauses for developers and leaves little room for negotiation. This lack of flexibility can deter project financing due to perceived risks. The creditworthiness of Electricity Viet Nam (EVN), the primary offtaker, also poses a challenge. EVN reported considerable financial losses in 2023, fueling concerns about its ability to fulfil long-term purchasing commitments (EVN, 2023).

## Policy instruments for VREs

The growing share of VREs has been facilitated by favourable incentive frameworks, including tax incentives, import and export duty exemption and a feed-in tariff system (FIT). FiTs are particularly suitable instruments for integrating variable output in the early stages of VRE deployment. Although the country is currently engaged in developing a new wholesale market, this is still in its pilot phase. According to Circular 45/2018/TT-BCT, renewable energy power plants (except hydropower) with a capacity greater than 30 MW have the right to choose whether to join the power market, meaning that the current framework leaves the decision to participate in the market to the power plants. Under the existing market framework, VRE is given priority in dispatch. Although it is not yet formalized into a market rule, the prioritisation will remain in place in the new wholesale market.

Several constraints pose a major barrier to the growth of VRE projects in Viet Nam. These include the high initial investment costs for solar and wind power plants and the burden of charges for connection to the transmission network. Specifically, developers must navigate the costs of land acquisition, which can be twice as high as in countries like India, and secure loans at interest rates around ten percent, reflecting the high perceived risk due to curtailment concerns in EVN contracts that impede access to more competitive international financing (Urakami, 2023). This is partly because the force majeure clause in solar and wind PPAs renders the projects' offtake risk quite high and excludes opportunities for project financing, especially by international lenders. Viet Nam faces additional challenges such as limited cross-border connections, inadequate system-wide planning to address transmission congestion arising from VRE project locations and the lack of a VRE forecasting framework.

### Evolution of the FiT mechanisms

In light of its ambition to spur growth in renewables, Viet Nam had offered attractive feed-in-tariffs (FiT) to solar and wind developers for a number of years. A feed-in tariff of 7.8 US cents per kWh was introduced for wind power plants in 2011, following the promulgation of Decision 37/2011/QD-TTg. In 2018, the rate was further increased to 8.5 US cents per kWh for onshore wind and 9.8 US cents per kWh for offshore wind plants that could commence operations by 1 November 2021. Similarly, the launch in 2017 of a feed-in tariff mechanism for solar developers in accordance with Decision 11/2017/QD-TTg aimed to spur rapid deployment of solar capacity. Under this mechanism, all types of grid-connected solar projects that could come online by 30 June 2019 would enjoy a fixed 20-year FiT of 9.35 US cents per kWh. To accommodate renewable projects that failed to meet the commercial operations date (COD) deadline, the solar FiT mechanism was extended for a second phase until December 2020 (i.e. COD by 31 December 2020), albeit with new, lower rates that varied for different types of solar installations – 7.09, 7.69 and 8.38 US cents per kWh for ground-mounted, floating and rooftop solar projects respectively.

The FiT mechanisms were bolstered by supportive measures such as land rent reductions and preferential tax treatments that collectively contributed to a substantial increase in VRE capacity, particularly in solar energy. However, the FiT scheme encountered challenges, notably in its alignment with broader power sector planning, including the Power Development Plan (PDP) and grid development strategies. This misalignment led to integration issues, affecting EVN's ability to effectively manage the influx of VREs and impacting the bankability of renewable projects.

### Transition to auction-based procurement

Viet Nam is exploring a possible transition towards a more sustainable model for VRE procurement, notably through the introduction of auction-based mechanisms in line with international practice. The transition from FiTs to auction-based procurement is driven by the need for a more competitive, transparent and efficient approach to renewable energy deployment. While no timeline has been announced for the implementation of an auction mechanism, work is underway at MOIT to design and develop the scheme, with the support of the Asian Development Bank (ADB) and the World Bank.

In the interim, solar and wind producers that failed to secure the FiTs that have expired are subject to bilateral negotiations with EVN on the purchase price, which may not exceed ceiling prices regulated under Decision No. 21/2023/QD-BCT – namely 1 184.90, 1 508.27, 1 587.12 and 1 815.95 Vietnamese dong per kWh for ground-mounted solar, floating solar, onshore wind and offshore wind respectively. This interim solution aims to strike a balance between fostering continued growth in VRE and managing the limitations imposed by the current regulatory and market framework. While the ceiling prices set during this transition phase provide some structure, they do not necessarily guarantee a predictable financial environment, as the negotiated prices can be lower than the ceiling and the ceiling itself may not be sufficiently high to ensure project viability. A floor price might offer greater predictability by providing a guaranteed minimum return, which could be more effective as a transitionary measure in minimising investor risk amid ongoing regulatory uncertainties.

### Introduction of new tariff framework – Circular 19

In early 2024, new regulations on tariff ranges for solar and wind power projects were introduced, aimed at establishing a clear post-FiT framework. The new Circular 19 sets out methods for determining tariff ranges annually for different regions based on irradiation data for solar projects and introduces the concept of standard power plants to determine ceiling tariffs. This framework aims to create a more structured and transparent pricing mechanism that reflects the true costs of generation. However, Circular 19 does not provide guidance on the selection of renewable energy projects or specific tariff determination for individual projects, which remains a significant area of uncertainty that needs to be addressed for further clarity and stability in the renewable energy sector.

Notably, Circular 19 applies to new solar and wind projects but does not cover plants already operating under existing PPAs with effective FiTs. It introduces the concept of “Standard Power Plants” as benchmarks for setting tariff ranges, which are intended to ensure fair pricing that reflects the true costs of generation. The RE tariff design in Circular 19 treats the contract prices for technologies like biomass, hydrogen and ammonia in much the same way as those for coal-fired and LNG-to-power projects, including both fixed and variable components. In contrast, solar and wind power projects feature contract prices comprising only a fixed price. These prices are capped at the ceiling price of the base year to maintain cost predictability and investment attractiveness. The contract price calculations exclude investment costs for transmission lines and substations and assumes that these costs will be recovered separately, ensuring the capping does not hinder the infrastructure development necessary for integrating VREs into the grid.

### Decentral renewables deployment – corporate PPAs

In July 2024, Viet Nam issued Decree 80/2024/ND-CP on Direct Power Purchase Agreements (DPPAs). Through the DPPA mechanism, large-scale electricity consumers will be able to contract electricity purchases directly with renewable energy generators. Decree 80/2024/ND-CP facilitates two forms of DPPAs – direct power purchase through a private connection (Physical DPPA) and direct power purchase through the national power grid (Virtual DPPA). Under the Virtual DPPA model, the seller and buyer would carry out their transactions under a contract-for-difference (CfD) arrangement with reference to the market price. To be eligible, renewable power generators must have at least 10 MW of installed capacity and participate directly in the competitive merchant market, while the buyer must have at least a 22 kV connection to the grid. On the other hand, parties to physical DPPAs are not expected to be constrained by any capacity or voltage requirements (EVNPECC3, 2023).

Other mechanisms that go beyond DPPAs and auctions to facilitate VRE growth are also in the pipeline. In November 2020, Viet Nam’s National Assembly passed the amended Environmental

Protection Law to legalise the establishment of a domestic carbon market in Viet Nam. Decree 06/2022/ND-CP tasks the Ministry of Natural Resources and Environment and Ministry of Finance with developing and implementing a national emissions trading scheme (ETS) and a carbon crediting mechanism. The ETS is set to commence pilot operations in 2027. In parallel, Viet Nam has been working with USAID to explore the development of a national renewable energy certificate (REC) ecosystem that could build upon the existing voluntary market for internationally RECs, helping it attract more investment (USAID, 2022).

**To augment the deployment of VREs in Viet Nam and address current challenges, several strategic actions and policy enhancements are required:**

- **Streamlined regulatory framework:** The establishment of a clear and consistent regulatory environment is crucial. Investors require assurance on policy stability to commit to long-term investments in VRE projects. Regulatory uncertainty remains a substantial barrier to investors at present. Clarity and predictability in the legal framework are the key to unlocking the necessary capital for VRE expansion. As such, the issues stemming from the misalignment between policy frameworks, including the Power Development Plan (PDP) and grid development strategies, will be dissected in greater depth in the section on market functioning. This deeper analysis will address how this misalignment has complicated the integration of VREs, affected EVN's operational efficiency and challenged the financial viability and bankability of renewable energy projects in Viet Nam.
- **Market-based mechanisms for VRE deployment:** Introducing auction-based procurement is essential. Not only will this ensure a competitive marketplace, it will also enhance the transparency and efficacy of VRE deployment. A transparent auction scheme and increased competition are also likely to attract international developers and lower tariffs, thereby benefitting consumers. In addition, further refinement and implementation of the DPPA mechanism to enable direct contracts between VRE producers and large consumers would enhance market flexibility.

***DER policies***

Viet Nam's Distributed Energy Resources (DER) policy, detailed within Decision No. 262/QD-TTg, exemplifies a progressive strategy to reshape the nation's energy profile by 2030, with a vision towards 2050. As part of this broader goal, the policy aims to increase the capacity of rooftop solar power, targeting the deployment of 2 600 MW of grid-connected rooftop solar for self-consumption. This capacity limit is modest, reflecting the government's cautious approach to expanding rooftop solar within the constraints of the current grid infrastructure.

The Northern Region is poised for a substantial increase of 927 MW, concentrated especially in industrial strongholds such as Hanoi and Hai Phong City that reported year-on-year growth in the Index of Industrial Performance (IIP) of 8.8 percent and 14.4 percent respectively in 2022 (General Statistics of Viet Nam, 2022). The Southern Region meanwhile, which is characterised by high industrial activity and urban energy consumption, is projected to receive the largest boost of 1 109 MW, driving significant strides towards energy self-sufficiency in these densely populated areas. In contrast, the Central Highlands and the Central Region are expected to see more modest increases, in keeping with their lower population density and industrial output. This differentiated approach not only fosters regional economic development but also aligns seamlessly with Viet Nam's overarching objectives of achieving energy independence and sustainability.

As reflected in the PDP8, MOIT's stance on rooftop PV has shifted in recent years towards prioritising self-consumption for businesses and residential units, largely because of the grid congestion issues that arose following the rapid surge in VRE capacity, particularly in the south and central regions. In December 2023, MOIT issued a draft decree on solar rooftop development that presents policy options for both grid-connected rooftop PV and off-grid rooftop PV. For grid-connected rooftop PV, any new developments are subject to the 2 600 MW capacity limit and would receive no compensation for any excess generation fed into the grid. For off-grid systems, no restrictions or targets have been set.

**Box 6. › Policy and planning framework for Viet Nam**

**National Power Development Plan 8 (PDP8), 2021-2030:**

- RE share of 30.9-39.2 percent by 2030, reaching 47 percent if JETP commitments are met.
- By 2050, RE to account for 67.5-71.5 percent.
- Electricity export capacity from renewables targeted at 5-10 GW by 2030.
- Battery storage targets set at 300 MWh by 2030 and 26 GWh by 2050.

**Viet Nam Green Growth Strategy, 2021-2030:**

- Increase in the share of RE sources, with a focus on transitioning towards green, clean and sustainable energy.
- Reduction in GHG emissions per GDP by at least 15 percent by 2030 and 30 percent by 2050 compared to 2014 levels.

**Renewable Energy Development Strategy (REDS), 2016-2030:**

- Renewable power generation to cover ten percent of total power generation by 2030.
- Power generation and electricity sales to reach ten percent RE by 2030 and 20 percent by 2050.
- Reduction in coal and oil imports to decrease greenhouse gas emissions by 25 percent by 2030 and 45 percent by 2050.

**The Just Energy Transition Partnership (JETP), 2023:**

- Revision of the peak carbon dioxide equivalent (CO2e) emissions target to 170 megatonnes (Mt) of CO2e by 2030.
- RE target increased to 47 percent by 2030.
- Reduction of the coal-fired generation project pipeline from 37 GW to 30.2 GW by 2030.

**Nationally Determined Contributions (NDCs), 2022:**

- Unconditional GHG emission reduction target of nine percent and a conditional target of 27 percent by 2030 in line with net zero targets and methane emission reduction plans.

**National Energy Masterplan (NEMP), 2021-2030:**

- RE to contribute 30.9 to 39.2 percent of total electricity supply by 2030, or 47 percent with JETP finance commitments. Electricity exports to reach five to ten GW by 2030.
- By 2050, RE to reach 67.5 to 71.5 percent of electricity supply.
- Green hydrogen production targets of 100 to 200 thousand tonnes annually by 2030, increasing to 10 to 20 million tonnes per year by 2050.

# Market and contractual arrangements

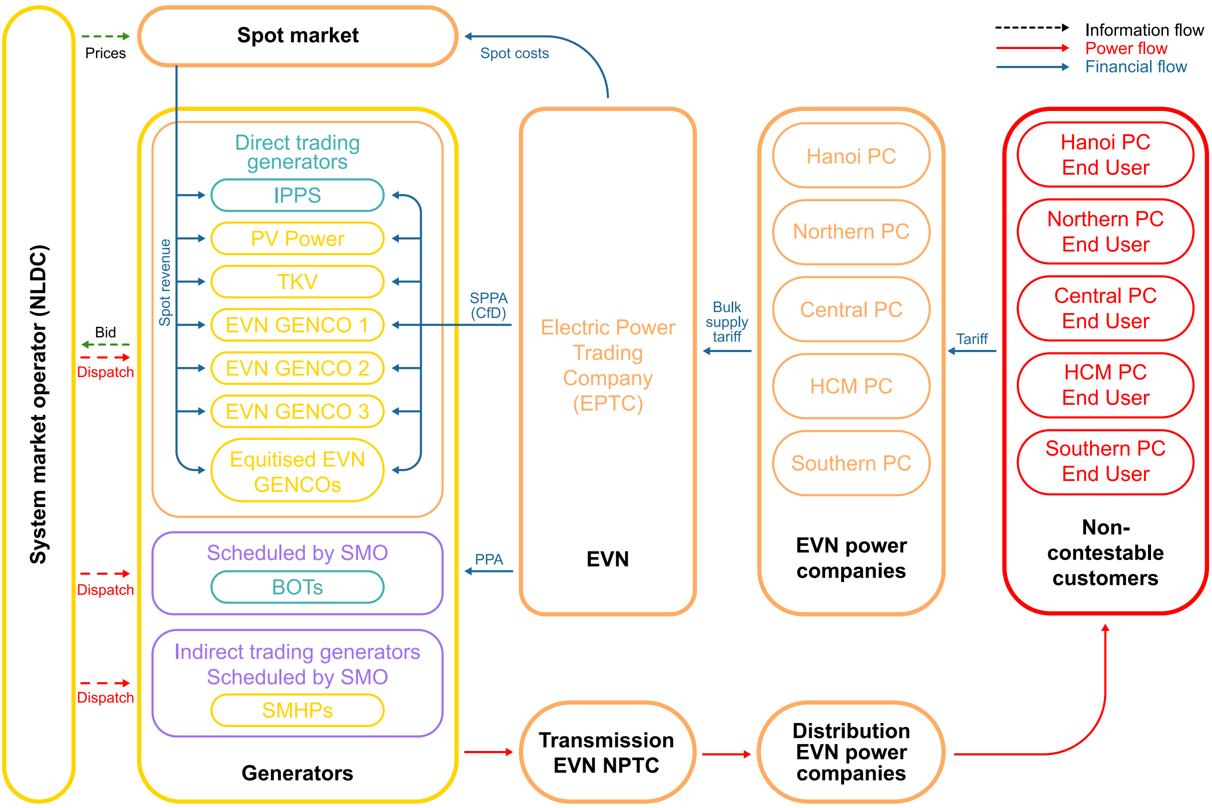
### Power market development

Power market reform in Viet Nam has been a deliberate and progressive pursuit spanning nearly two decades. The country's resolve to reform was set forth in the Prime Minister's strategic roadmap issued in 2006, which plotted a course towards a competitive electricity market. The roadmap aimed to unlock market efficiencies and address the growing energy demand driven by Viet Nam's dynamic economic growth.

Emulating aspects of the Australian energy-only market model, which is renowned for its efficiency and responsiveness to market signals, Viet Nam's approach has been to adapt and integrate similar principles within the context of its own market design. This inspiration from Australia's market structure is evident in the multi-phase transition plan laid out by Viet Nam's government, underscoring the nation's commitment to restructuring its energy sector.

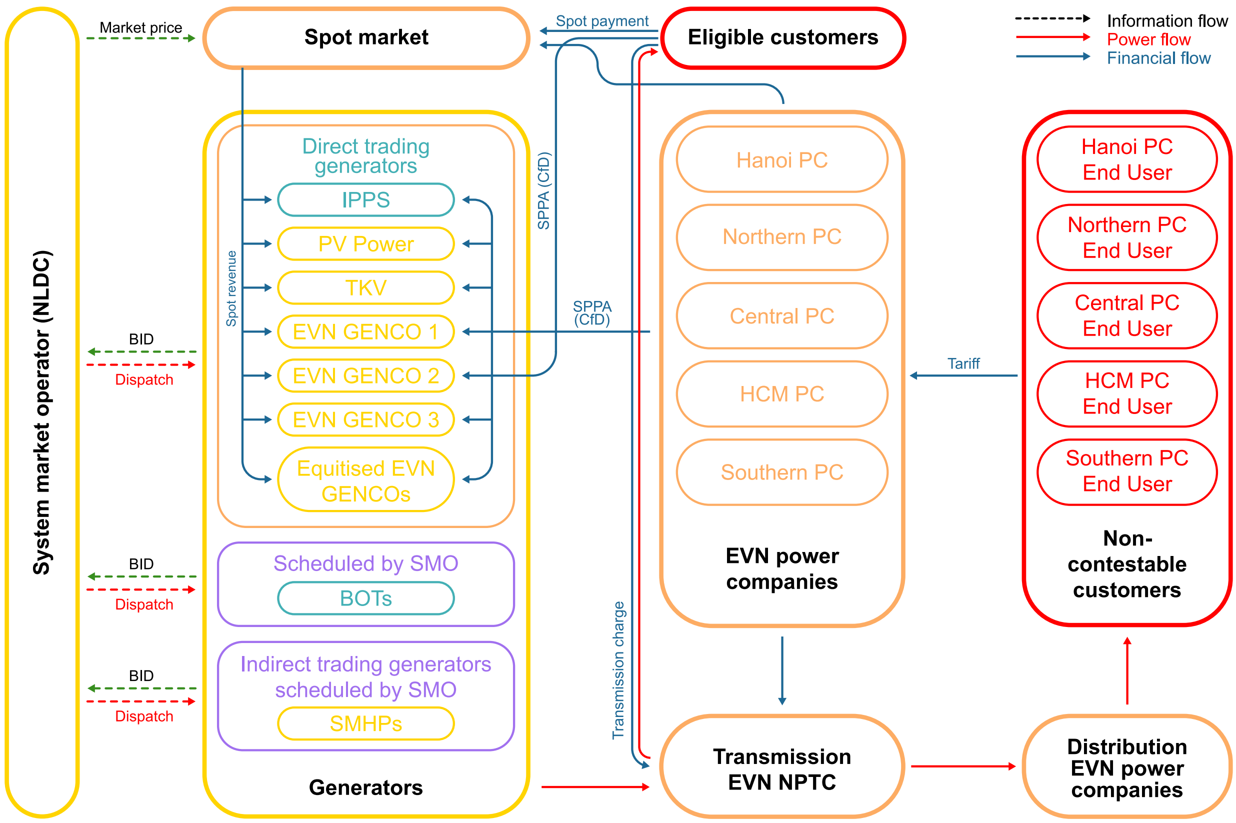
The initial phase began with the introduction of the Viet Nam competitive generation market (VCGM) in 2011. This market represented the first layer of Viet Nam's evolving electricity sector and was structured as a one-sided cost-based pool in which generation companies, including EVN and other state-owned enterprises (SOEs) with capacities of 30 MW or larger, were permitted to enter into competition. These entities began to actively vie for the opportunity to sell their generated electricity to the Electric Power Trading Company (EPTC), designated as the sole buyer in this nascent market architecture. The VCGM operated on the principle of the costs of production being pooled together and the selling price being determined on the basis of the aggregate cost of generation. The EPTC, acting as the central buyer, then allocated electricity from this pool to various distribution companies based on their demand and the agreed-upon tariffs. This cost-based approach was aimed at ensuring that the price of electricity reflected the actual cost of generation, thereby promoting transparency and efficiency in the nascent stages of the market's development. The introduction of the VCGM was a critical first step in a broader strategy to transition from a vertically integrated model to a more competitive market structure, paving the way for subsequent phases of reform that would introduce new dynamics and market players into Viet Nam's power sector.

**Figure 10. › Current VWEM**




As of 2024, the transition from the VCGM to the Viet Nam wholesale energy market (VWEM) remains an ongoing process, though the VWEM already began trial operations in 2016. The anticipated shift in market structure has yet to be fully realised and the EPTC still maintains a significant role in the electricity market. Although generators and power companies (PCs) have begun entering into standardised power purchase agreements (SPPAs), their impact on the market is minor. The bulk supply tariff (BST), a regulated rate at which PCs purchase electricity from the EPTC, is still in effect, which suggests that the envisioned competitive pricing mechanisms have not yet been fully implemented. Additionally, the deployment of the direct power purchase agreement (DPPA) mechanism has encountered delays. Following a directive from the Prime Minister dated 15 August 2023, Decree 80/2024/ND-CP on Direct Power Purchase Agreements (DPPAs) was only issued in July 2024.

**Figure 11. › Complete VWEM**




The VWEM represents a significant evolution from the previous VCGM system, aiming to introduce a more dynamic and competitive energy sector. While the VCGM was a one-sided, cost-based pool market primarily involving state-owned entities and large-scale generators, the VWEM is designed to be a two-sided market that allows for a broader range of participants and more flexible pricing. Unlike the VCGM, where prices are determined on the basis of the pooled costs of production, the VWEM is structured to reflect actual market conditions where prices are influenced by supply and demand dynamics. This design difference is particularly relevant to the integration of VREs.

The VWEM's advantage lies in its ability to respond to short-term market dynamics, sending out price signals that inform flexible producers when to ramp their generation up or down. This not only supports the integration of renewables by improving dispatch efficiency and aiding the system operator in balancing the grid, but also has the potential to reduce overall system costs. Additionally, if nodal pricing is adopted, this could help mitigate grid congestion, further optimising the system. Transitioning to the VWEM is a complex process that requires realignment of the entire power market structure in Viet Nam. As of 2024, the full potential of this market model has yet to be exploited. Although the EPTC continues to play a substantial role and the implementation of standardised power purchase agreements (SPPAs) has commenced, the move towards a fully operational competitive pricing mechanism is incremental.

A key aspect of the ongoing transition is the market integration of assets operating under build-operate-transfer (BOT) PPAs. These projects represent a form of public-private partnership that is crucial for infrastructure development, including in the power sector. However, BOTs have not begun to directly participate (i.e. place bids) in the wholesale market. This indicates a gap between the planned market mechanisms and the status quo development of the power market.

Dispatch arrangements primarily follow a cost-based system that operates largely on the principle of marginal cost pricing and thus favours consistently available and predictable power sources. VREs such as wind and solar are increasingly predictable thanks to better forecasting techniques. VREs inherently exhibit variable generation patterns due to their dependence on weather conditions. This variability challenges the effectiveness of a cost-based dispatch system that lacks mechanisms to dynamically adjust to the fluctuating output of VREs, potentially leading to inefficiencies in grid management and reliability. While some merit order dispatch principles are in place, contractual obligations often prevent their full implementation and renewables do not consistently benefit from priority dispatch. While significant strides have been made since the initiation of the power market reform roadmap, Viet Nam's power sector is still transitioning towards the envisioned VWEM. The status quo suggests that further efforts are necessary to fully realise the competitive market structures and achieve the efficiency and responsiveness that such a market promises.

To achieve the intended benefits of the VWEM, especially in enhancing renewable energy integration, Viet Nam will need to:

- **Finalise the operational framework of the VWEM:** The specific roles, rules and responsibilities of market participants must be clearly defined to facilitate effective market operation.
- **Formalise priority dispatch for VREs:** To enhance the sustainability and efficiency of the VWEM, it is crucial to formalise priority dispatch for VREs. While VREs are often given dispatch priority in practice due to their low marginal costs and environmental benefits, this priority is not yet enshrined as a formal market rule. The absence of a formalised priority dispatch policy means that the integration of VREs into the grid is subject to discretionary decisions, which can lead to inconsistencies in how these resources are utilised.
- **Scale DPPA mechanisms:** Accelerate the deployment of DPPA mechanisms to encourage the growth of VRE through direct agreements between producers and large consumers.

### Wholesale market arrangements

At present, the VWEM operates as a day-ahead gross pool market with 30-minute trading and dispatch intervals. Generators submit cost-based bids within their respective permitted statutory range. Each transaction interval is crucial as the market is cleared at the system marginal price (SMP), considering the unconstrained least-cost generation schedule. This schedule is subject to a cap for the SMP that is set by the Ministry of Industry and Trade (MOIT).

The VWEM compensation to producers, known as the full market price (FMP), equates to the sum of the SMP and a predetermined capacity add-on (CAN) payment. These CAN payments are calculated annually for each transaction cycle, covering the capacity scheduled for providing not just energy but also ancillary services. The intention behind the CAN payment is to bridge the revenue gap that may arise from the spot market for the best new entrant (BNE) – essentially, the most cost-effective baseload thermal plant among the new market entrants – ensuring its operational costs are covered within a year.

In Viet Nam, the EPTC and generators who directly bid on the wholesale market are parties to standardised power purchase agreements (SPPAs), which are in effect contracts for difference (CfDs) that mitigate the parties' exposure to price volatility in the spot market. Differences between the strike price and the FMP are payable by either the generator or the EPTC with respect to the agreed-upon percentage of the plant's projected available capacity in a given year (Qc = committed capacity), which by law must range between 60 and 100 percent. The current role of the EPTC as the direct offtaker is transitional, with plans for suppliers to gradually replace it in this capacity in order to foster a more competitive market environment.

Together, these arrangements have served to reduce financial volatility for direct market participants and EVN over the years. The CAN payment mechanism, as a fixed revenue component, enhances investor certainty by providing a stable income stream for recovering capital costs. However, other limitations to price discovery in the VWEM, such as the SMP cap, can dampen market signals that would otherwise encourage investments in new capacity. While the CAN payment contributes to short-term financial stability, the restrictions on price signals may have implications for long-term resource adequacy in Viet Nam. To ensure continued investment in new capacity, it is crucial to address these limitations and enhance the overall market design.

Outside the VWEM framework, the lack of transparency in the direct negotiation of PPA terms between the EPTC and foreign-invested build-operate-transfer (BOT) power plants has undermined investor confidence. Such PPAs are negotiated separately and are not required to reference prices in the VWEM, leading to concerns about price alignment with market conditions. In addition, there is no legal provision that mandates referencing of prices in the VWEM as the basis for price negotiation. Approximately 60 percent of generators continue to remain indirect participants in the VWEM. BOT power plants' bids are placed on their behalf by NLDC based on the respective contract prices and outputs in their long-term PPAs with the EPTC. On the other hand, EVN-owned strategic multi-purpose hydropower plants (SMHPs) are scheduled by NLDC on the basis of a water valuation model that seeks to optimise their utilisation for both energy and ancillary services.

- ► **Viet Nam could benefit from adjusting the SMP cap to better mirror real-time market conditions and cost structures.** This would enhance price signals and encourage the necessary investments in new VRE capacities.
- ► **Advance the transition to full market-based electricity pricing:** Building on the foundations of the VWEM, Viet Nam should continue the transition towards full market-based electricity pricing. This would involve gradually reducing government subsidies and regulatory price controls at the retail level, allowing prices to better reflect the true costs of electricity generation and market dynamics. To balance affordability and sustainability, the government should implement targeted subsidies or social tariffs to protect low-income and vulnerable consumers from potential price increases. This transition will encourage more efficient energy use, attract necessary investments in the energy sector and ultimately support the development of a more resilient and financially sustainable electricity system.
- ► **Expand direct market participation to include BOT assets to unlock greater operational flexibility from conventional generators:** It is important to encourage direct participation in the VWEM from all generators, including those operating under BOT agreements. Many BOT projects (coal and renewables) currently operate under long-term PPAs, which provide little incentive for direct market participation. This limits competition, market liquidity and short-run price discovery. To address this, Viet Nam could consider adopting "vesting contracts," a strategy used in other countries such as Australia to gradually transition generators from PPAs to full market competition. Vesting contracts offer a phased

approach that maintains revenue certainty for generators while gradually exposing them to spot market developments. This would in turn compel conventional assets to respond to short-term price signals, encouraging greater operational flexibility to support the integration of variable supply sources.

### Market integration of VREs

Viet Nam's power market is undergoing significant shifts, with implications for the integration of variable renewable energy (VRE) sources such as solar and wind power. Viet Nam's RE plants are required to report anticipated generation availability to NLDC, which then forecasts generation based on predicted weather conditions. However, the VWEM is contending with notable challenges. VRE plants face substantial revenue risks due to transmission network bottlenecks, primarily on 110 kV lines. The rapid deployment of solar capacity, spurred by location-agnostic feed-in tariffs (FiTs), has not been matched by equivalent growth in transmission and distribution, leading to significant congestion and output curtailment.

Currently, solar and wind generators do not directly bid on the VWEM. The lack of participation incentives is attributed to the SMP cap, which limits price formation in the VWEM, and, crucially, to the existence of long-term contracts with EVN. Additionally, regulatory inconsistencies contribute to this situation. For instance, while MOIT Circular 45 allows wind and solar plants with over 30 MW capacity to voluntarily bid in the VWEM, MOIT Decision 8266 explicitly prohibits VRE units from participating in the VWEM, irrespective of their capacity. This conflicting regulatory environment adds to the complexity and challenges facing the integration of renewable energy into Viet Nam's power market. Additionally, given that the VWEM's marginal price is mostly driven by coal's short-run marginal costs, there is little commercial incentive for wind and solar plants to forgo their much higher FiT rates to participate in VWEM.

Drawing on international experience such as that gained by Australia's NEM, Viet Nam recognises the need for legislative reforms to better align market mechanisms with the rapid growth of VRE. Such alignment is essential to address the existing issues of transmission network constraints and the inconsistencies in regulatory frameworks. The rapid pace of VRE deployment, driven by tightening electricity supply margins and delays in thermal power plant procurement, highlights the urgency for regulatory evolution. This necessity is underscored by the operational conditions in the southern regions, where an oversupply has led to grid congestion and strategic curtailment of generation sources, including RE independent power producers (IPPs).

Insufficient ancillary services, inadequate market signalling and inflexible power PPAs significantly hinder the integration of VREs in Viet Nam. These deficiencies prevent the electricity market from responding effectively to the variability inherent in VRE sources. The VWEM's development should foster an environment in which price signals reflect actual system conditions and incentivise not only traditional dispatchable generators to adjust their output as necessary. A gradual shift from a single-buyer model to a more diversified market, where larger consumers and power corporations can directly interact with generators, is key. Initially, zonal pricing could be introduced to better reflect regional conditions, eventually transitioning to nodal pricing to manage more localized congestion and system needs.

Addressing the challenges of VRE integration, Viet Nam's market reforms can incorporate lessons from the Australian NEM, particularly in enhancing ancillary services, improving market signalling and ensuring the robustness of PPAs to reflect both long-term stability and short-term market dynamics.

### Ancillary services

The electricity network in Viet Nam is currently maintained via a centralised process managed by the National Load Dispatch Center (NLDC), where capacity allocation for ancillary services is essential for maintaining system stability. Currently, EVN relies heavily on strategic multi-purpose hydropower plants (SMHPs) for frequency regulation. According to the terms of PPAs, BOT power stations are also obliged to provide a range of ancillary services, including operating and spinning reserves as well as balancing services, without any additional cost to EVN, as stipulated in Clause 3.1b of their agreements. Despite these provisions, Viet Nam's grid faces limitations, particularly in frequency regulation capacity and operational reserve, which poses significant risks to system reliability. This is exacerbated by the growing penetration of VREs, which introduces greater variability into the power system.

Even before the recent surge in renewables capacity, system frequency in Viet Nam's network has historically fluctuated considerably beyond the stipulated range of 49.8 Hz and 50.2 Hz (JICA, 2021). As VRE generation increases, it will become increasingly critical for Viet Nam to introduce mechanisms such as a market for ancillary services to procure capacity for frequency control and efficiently direct resources towards system balancing.

Viet Nam's approach to managing its electricity network, especially in terms of ancillary services, reveals a system in transition that is grappling with the dual challenges of integrating a growing share of VREs and updating its infrastructure and regulatory frameworks to ensure system reliability. The integration of VREs, particularly wind and solar, is accelerating, necessitating a more sophisticated approach to ancillary services which are critical for maintaining the stability and reliability of the power grid.

The current ancillary services framework lacks compensation mechanisms that would encourage the delivery of these essential services. Additionally, older power stations, which lack Automatic Generation Control (AGC) and governor functions because they went online before the 2015 requirements were introduced, are unable to contribute to frequency control and reserves, despite their potential capability.

► **Viet Nam should continue to prioritise the creation of a market for ancillary services as part of its evolving electricity market design.** Establishing such a market would encourage cost-effective procurement for system services and optimise resource allocation for system balancing – which is crucial when it comes to maintaining reliability amid the increasing integration of VREs.  As part of the target model for the VWEM, co-optimising energy and ancillary services would further enhance efficiency and cost-effectiveness. Implementing unified bidding processes for both energy and ancillary services would streamline operations, reduce complexity and ensure the economic utilisation of resources. This approach would help distribute the costs and benefits of ancillary services equitably across various technologies, service types and ownership models, paving the way for a resilient and future-proof power sector.

### Retail tariffs

The dynamics of retail electricity pricing and the financial landscape for RE projects are closely interlinked in Viet Nam, presenting a complex challenge for energy market stakeholders. Power corporations (PCs) purchase electricity from the EPTC at a regulated bulk supply tariff and sell to consumers at regulated retail tariffs that are uniform across the country for each consumer segment. Retail tariffs are approved for a multi-year period by the Prime Minister. The regulations stipulate that EVN is permitted to hike retail tariffs by up to five percent. Increases beyond the five and ten percent thresholds require approval from

MOIT and the Prime Minister, respectively.

The commercial sector is subject to the highest rates, ranging from 1 465 to 4 937 Vietnamese dong per kWh depending on time-of-use and voltage level. Residential users, on the other hand, face stepwise power tariffs that begin at 1 806 Vietnamese dong per kWh for the first 50 kWh and increase to 3 151 per kWh for the 401st kWh onwards. Direct subsidies are available for low-income households and other eligible beneficiaries (e.g. war veterans). Retail tariffs for industrial users do not deviate significantly from residential rates, at between 1 044 and 3 314 Vietnamese dong per kWh. Retail tariff levels in Viet Nam are not reflective of electricity generation costs or the scarcity of electricity supply which, in addition to high fuel prices, has significantly strained EVN's balance sheet in recent years. In 2023, EVN reported a pre-tax loss of 17 trillion Vietnamese dong despite two retail price hikes over the year.

Addressing financial barriers, streamlining regulatory frameworks and ensuring that retail tariffs better reflect the true costs of electricity supply and generation are essential steps for Viet Nam to foster a more resilient and sustainable power market that can effectively integrate an increasing share of renewable energy.

## Recommendations

### Pillar 1 › Provide long-term investment certainty for VREs

- **Resume centralised procurement to build on earlier deployment successes: Adopt competitive auctions with locational factors to support targeted renewables investments.** Currently, Viet Nam lacks a formal tender or auction mechanism for renewable energy, creating considerable uncertainty for large-scale VRE investments. Enhancing the strategic deployment of renewable energy projects by integrating locational benefits into the competitive bidding process would optimise the overall energy mix and facilitate smoother grid integration. By developing a procurement framework that considers regional VRE generation potential, grid infrastructure capacity and demand projections, projects could be strategically prioritised in locations that have high renewable potential or are close to underutilised load centres. Such a targeted approach to infrastructure investment would reduce transmission losses and congestion, improve system reliability and promote a more balanced and efficient energy supply. Additionally, prioritising development in areas that offer the highest environmental and economic returns fosters regional economic development.
- **Incorporate curtailment compensation in renewable energy PPAs:** Establish a robust compensation framework within power purchase agreements that provides financial security to RE producers for energy not dispatched due to grid constraints or excess generation. This could be implemented by specifying contractual terms within PPAs that mandate a minimum guaranteed payment to VRE producers for curtailed energy, calculated on the basis of a percentage of the contracted rate. By reducing the financial risks associated with curtailment, this approach would incentivise higher investment in renewable technologies by giving investors greater certainty about returns, even under fluctuating operational demands.

- **Continue introducing corporate PPAs for renewables.** DPPAs would allow large-scale electricity consumers to contract electricity purchases directly with renewable energy generators, supporting investments beyond central mechanisms. Both virtual and physical DPPA models have been introduced. The successful implementation of DPPAs in Viet Nam would require third-party access to the national grid, ensuring that different energy producers can utilise existing infrastructure to deliver power directly to consumers. Additionally, the introduction of new network tariffs is essential to accurately reflect the costs associated with transmission and distribution under this model. These tariffs would cover expenses such as power system operation and market operation fees that are vital for maintaining grid stability and fairness in pricing.

### Pillar 2 › Enhance system flexibility to integrate variable renewables into the system at the least cost

- **Prioritise the transition to a competitive short-term market to unlock opportunities for greater operational flexibility.** The VWEM will shorten dispatch intervals to five minutes, optimise energy and reserve bids, introduce locational marginal pricing and herald a shift to competitive pricing based on supply offers and demand bids. The new market arrangements will allow dispatch schedules to be updated closer to real time in response to fluctuating output and load, yielding operational cost savings and supporting VRE integration. Initially scheduled for implementation in 2019, the transition from the current cost-based pool to the target model of the VWEM promises to bring significant benefits and should be prioritised.
- **Formalise the establishment of an ancillary services market to procure short-term system flexibility cost effectively:** Viet Nam should formalise the development of an ancillary services market that is specifically adapted to the dynamics of the energy mix, which is increasingly dominated by VREs. This market should compensate for services that maintain system balance and support the integration of renewable energies, such as ramping requirements, frequency regulation and voltage support. Policymakers should ensure that the compensation mechanisms in this market are attractive enough to encourage the provision of these essential services, thereby enhancing grid stability and enabling more substantial integration of renewable resources.
- **Expand direct market participation to BOT assets to unlock greater operational flexibility:** It is important to encourage greater direct participation in the VWEM from all generators, including those operating under build-operate-transfer agreements. Many BOT projects, both in coal and renewables, operate under long-term power purchase agreements that provide minimal incentives for direct market participation. This limits competition, market liquidity and price discovery. To address this, Viet Nam could consider adopting “vesting contracts,” a strategy used in other countries such as Australia to gradually transition generators from PPAs to full market competition. Vesting contracts offer a phased approach, ensuring revenue stability for generators while progressively increasing their exposure to spot markets. This would in turn compel conventional assets to respond to short-term price signals, encouraging greater operational flexibility to support the integration of variable supply sources.
- **Formalise priority dispatch for VREs:** Although VREs are typically given dispatch priority in practice due to their low marginal costs and environmental advantages, this priority has not yet been established as a formal market rule. Without a formalised priority dispatch policy, the integration of VREs into the grid remains vulnerable to discretionary decisions, potentially leading to inconsistencies in the utilisation of these resources.

**Pillar 3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs**

- **Introduce a forward reserve market to create revenue certainty for power plants providing offline operating reserves.** Once fully operational, the VWEM is expected to co-optimise energy and ancillary services. However, power plants reserving capacity for system security need to be adequately compensated for doing so. The system and market operator could procure forward reserves through auctions, ensuring that backup power resources are adequately remunerated and available during peak demand periods or when renewable sources are offline.

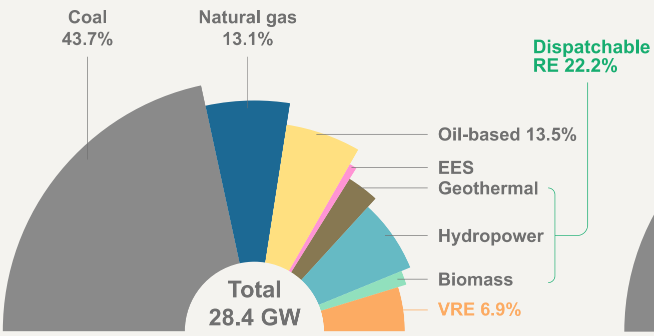
**Pillar 4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets**

- **Halt approved coal power projects.** Though the economics of coal are diminishing, approximately 6 GW of coal power is still planned to come online in Viet Nam by 2030. These projects should be cancelled to avoid increasing the system costs of the country's evolving renewables transition.
- **The introduction of an emissions trading system** could promote the efficient retirement of carbon-intensive assets. However, this would require an ambitious design that allows merit order effects to materialise.

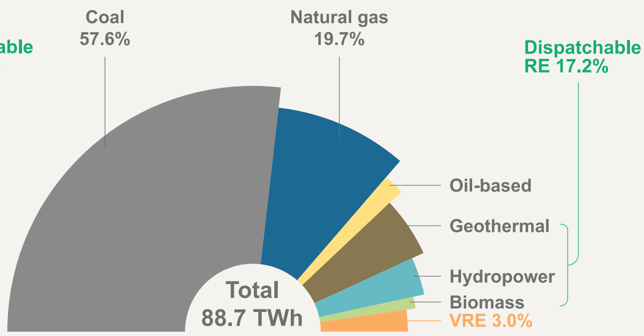
**Pillar 5 › Ensure affordable electricity for consumers while maintaining the sector's financial sustainability**

- **Transition to full cost recovery while protecting vulnerable consumers:** Viet Nam's current approach, characterised by low retail electricity prices and capped coal prices, has kept electricity affordable for consumers. As the power sector evolves, however, and particularly as VRE sources are increasingly integrated, there will be a need to transition to full cost recovery to ensure EVN is in a financial position to drive network and flexibility investments. The government could gradually adjust retail electricity tariffs to better reflect the true cost of electricity production. This transition should be accompanied by the establishment of robust safety nets to protect vulnerable consumers from potential price increases.
- **Convert subsidies into investment support:** Existing subsidies, particularly those that keep electricity prices artificially low, could be restructured to create targeted investment support schemes. For example, investment support could be provided for rooftop solar installations for low-income households. Such schemes could offset the costs currently borne by the government in the form of electricity subsidies.

# 6 The Philippines – a restructured system with market competition




Installed generation capacity in 2022




Electricity generation in 2022

**0.72**

Grid emissions factor ($tCO_2e/MWh$)

Source: EDGAR, 2023; DOE; 2022; DOE, 2023; IEOP, 2022; Statista, 2024.

### Table 7. › Overview of key findings for the Philippines*

| | Enabler | Barrier |
|---|---|---|
| **Investment certainty for variable renewables** | • Renewable energy auctions award 20-year bankable power supply agreements<br>• Priority dispatch for VREs<br>• Fiscal incentives<br>• Incentives to attract private and foreign capital | • Power supply agreements for baseload power include more favourable terms than those for VREs<br>• RE auction design issues (periodicity, low bid caps)<br>• Variety and uncertainty of market products (energy, reserves, RECs etc.) |
| **System flexibility and VRE integration** | • Sophisticated market design for dispatch<br>• High time resolution: five-minute interval; gate closure close to real time (nine minutes)<br>• Geographical dispatch resolution (nodal)<br>• Ancillary services market | • Over-contracted capacity from baseload plants<br>• Long-term contract design increases system costs of an inflexible baseload power fleet<br>• Biased bidding distorts centralised market-based dispatch as producers must honour bilateral delivery commitments |

| | Enabler | Barrier |
|---|---|---|
| **System adequacy** | • Shift towards expansion of domestic resources<br>• Long-term contracts (PSAs) to secure supply | • Limited incentives to invest in flexible assets<br>• Legacy of a system designed for baseload capacity<br>• Network capacity constraints |
| **Phase-out of carbon-intensive assets** | • Moratorium on new coal power plants | • Power supply agreements shield costly and inefficient fossil fuel plants from market risks (incl. stranded asset risks) |
| **Affordability** | • Lower tariffs for contestable consumers<br>• Net-metering programmes<br>• Consumers are exposed to high and volatile fuel prices which greater VRE deployment would mitigate | • Power supply agreements fully hedge fossil power producers. Consumers bear the associated costs<br>• Reliance on imported fossil commodities<br>• Cost savings from RE deployment not reflected in lower tariff<br>• Transition and stranded asset risks are passed on to consumers (long-term contract design)<br>• Weak incentives for distribution utilities to improve procurement management |

*recommendations are provided at the end of the chapter

The Philippines is one of the few countries in the region with a liberalised electricity sector. The Electric Power Industry Reform Act (EPIRA), enacted in 2001, reshaped the country's previously vertically integrated power sector, unbundling it into four distinct segments. Generation and retail segments were opened to competition, while transmission and distribution remained regulated natural monopolies (see "Market structure" section). The EPIRA laid the foundation for subsequent policy reforms aimed at reforming the sector from a state-centred to a market-oriented model. This included privatising state-owned generation assets to ease the financial strain on state-owned entities, chiefly the vertically integrated utility National Power Corporation (NPC). Beyond alleviating stranded debt, restructuring aimed to mobilise private capital to meet the investment needs of the growing economy in the hope that it would eventually lower tariffs for end consumers (see "Institutional structure" section).

Despite early efforts to reform the sector, electricity prices in the Philippines are among the highest in the region. Besides the EPIRA, the phase-out of government subsidies and a heavy reliance on imported fossil fuels for power generation are often cited as factors to explain the high electricity prices. However, the design of power supply agreements (PSAs) is a factor that has been overlooked but contributes to higher electricity prices. PSAs secure baseload power plants' revenue and shield them from dispatch risk. This risk is transferred to end consumers, exposing them to higher electricity costs.

The current design of PSAs in the Philippines prioritises baseload generation expansion over flexible and clean energy sources. PSAs keep fossil baseload plants' revenues stable irrespective of their load factors, with capacity remuneration increasing when the plant is underutilised, i.e. dispatched less. This incurs additional costs for the system, particularly when integrating variable supply sources, and exposes consumers to disproportionate costs and risks. Furthermore, PSAs interact with the mandatory wholesale spot market, distorting price signals in the system and undermining dispatch efficiency. This problem is exacerbated by weak incentives for suppliers to efficiently manage their energy procurement, leading them to pursue regulatory or bureaucratic compliance rather than seeking lower costs of energy (see "Market and contractual arrangements" section).

PSAs have locked baseload power into the system but are a key instrument for building RE capacity and meeting national targets. Ensuring that RE plants have access to PSAs and creating a level playing field in the competitive selection process is vital to scaling up the installation of (V)RE plants.

The Philippines aims to achieve a 35 percent share of renewables in its electricity generation mix by 2030 and a 50 percent share by 2040. The Renewable Energy Act of 2008 is the cornerstone of these efforts. RE support mechanisms include the Renewable Energy Portfolio Standard (RPS), renewable energy auctions under the Green Energy Auction Program (GEAP), priority dispatch and the Green Energy Option Program (GEOP) (see "Policy instruments for VREs" section).

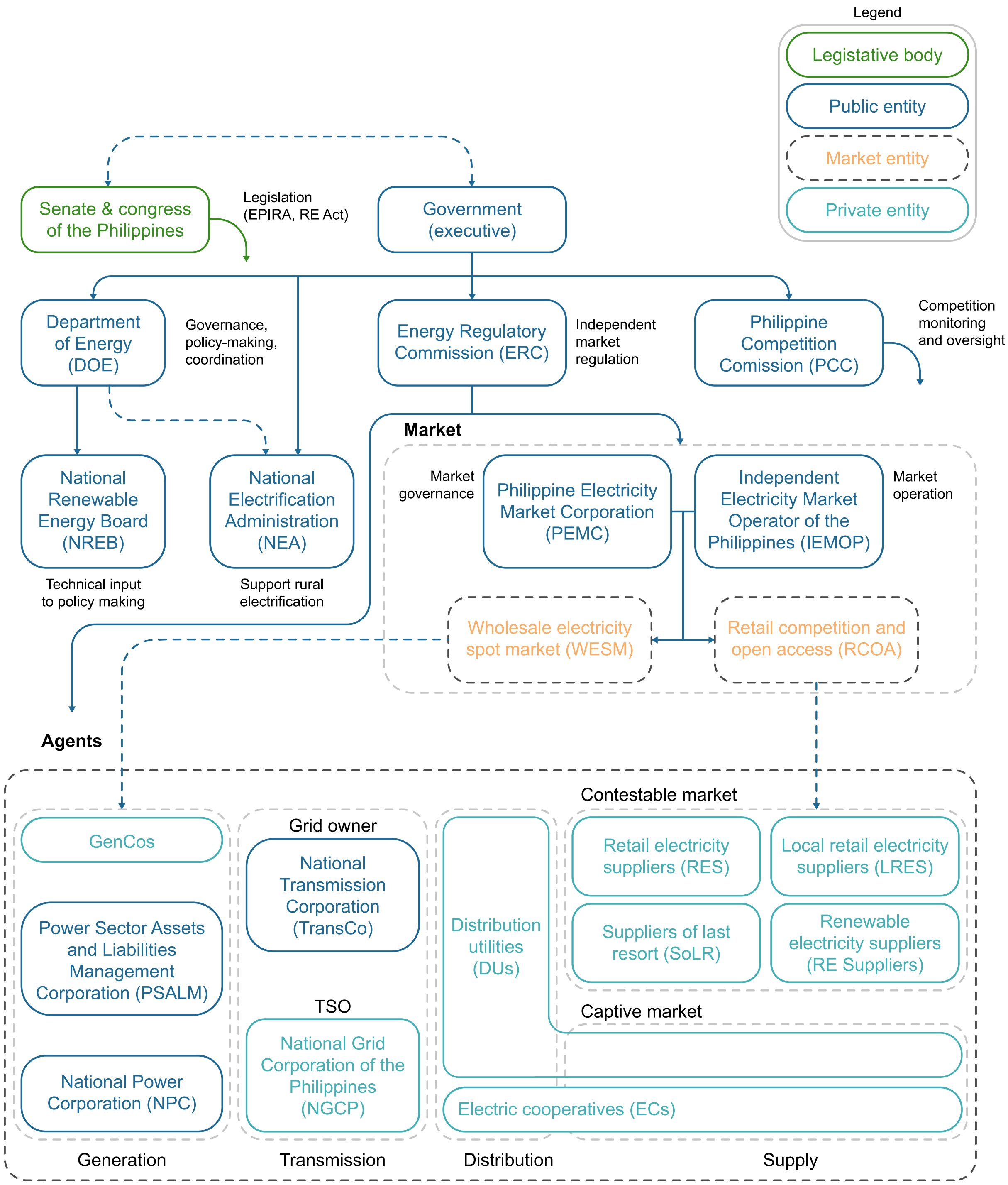
Following a fully subscribed first renewable energy auction in 2022, the second round of the Green Energy Auction Program (GEAP) fell short of its (increased) target by awarding 30 percent of the targeted 11.6 GW capacity. Concerns about the price caps set by the regulator and uncertainty about the transmission network's readiness to accommodate the additional capacity were key factors that resulted in the auction round being undersubscribed. The results were despite preceding policy reforms that eased restrictions on foreign investment in the renewable energy sector, removing the previous 40 percent limit on foreign ownership with the aim of attracting more participation and investment in renewable energy projects.

The Philippine electricity market has undergone several reforms in recent years. First, the wholesale electricity spot market (WESM) was enhanced by setting shorter trading intervals and integrating minimum technical capacity constraints into generators' price bids in 2021, and in January 2024 was complemented by a reserve market for ancillary services. In addition, the WESM began commercial operations in Mindanao in early 2023 following the implementation of the Mindanao-Visayas Interconnection Project (MVIP) that connected Mindanao to the national grid.

Building upon the recent upgrades to the WESM, several additional features are slated for implementation. Plans include the introduction of demand-side bidding in the WESM to incentivise consumer participation and the implementation of financial transmission rights (FTRs) to hedge price risks associated with differences between nodal prices in the grid. Additionally, preparations for the third round of the GEAP, targeting hydro and geothermal projects alongside other variable renewable technologies, underscore the government's commitment to expanding RE capacity and diversifying the energy mix. Moreover, discussions are underway to introduce futures and capacity markets to attract investors, ensure fair competition and facilitate system expansion to meet growing demand. Alongside these reforms, discussions have commenced regarding the introduction of contracts for difference (CfDs) as a voluntary mechanism by which to provide flexibility and diversification in procurement strategies.

## Institutional structure

**Figure 12. › Institutions and responsibilities in the Philippine's electricity sector**



Multiple government institutions regulate and administer the Philippines' electricity sector. The Congress of the Philippines, a bi-cameral legislature comprising the House of Representatives (lower body) and Senate (upper body), and the national government are mandated to introduce energy sector legislation (RA11571). Headed by the President, the executive arm of the national government is responsible for implementing energy and electricity laws through regulations and policies. The current institutional set-up in the Philippine power sector was established under the landmark Electric Power Industry Reform Act (EPIRA) of 2001 (RA 9136). Another landmark legislation was the Renewable Energy Act of 2008, which provides the legal foundation for all policies and programmes concerning RE resources in the country.

Several institutions were created under the EPIRA to govern the industry's transformation, including the Energy Regulatory Commission (ERC), the National Transmission Corporation (TransCo) and the Power Sector Assets & Liabilities Management (PSALM) Corporation. The EPIRA also established mechanisms such as the wholesale electricity spot market (WESM) and the retail competition and open access (RCOA) system to enhance market competition and efficiency (see more details in the section Market ).

The RE Act led to the creation of two new institutions – the National Renewable Energy Board (NREB) and the Renewable Energy Management Bureau (REMB). The REMB, housed within the Department of Energy (DOE), is responsible for planning, formulating policy and conducting technical research on the development of the country's renewable energy resources. The NREB's role is to provide technical input to the DOE in the policymaking processes and during monitoring of the RE Act (RA 9513).

The DOE is the apex energy governance body in the Philippines. It is responsible for formulating policy, coordinating and implementing programmes and projects and conducting long-term integrated energy planning. It prepares the Philippines Energy Plan, the Power Development Plan and the National Renewable Energy Program (DOE, 2019).

The ERC serves as the independent regulator. Its mandate is to enforce market rules, foster market competitiveness, penalise abuse of market power and protect consumer interests. It formulates rules and regulations for the market, sets tariff structures, wheeling rates and auction price caps, approves costs passed on to consumers, approves bilateral PSAs and ancillary service procurement agreements and grants licences and permits to market actors (ADB, 2018; RA 9136).

The National Electrification Administration (NEA), an agency attached to the DOE, aims to provide electricity to rural, remote and underserved areas. The NEA supports electric cooperatives (ECs) by guiding and assisting them in conducting competitive selection processes (CSP) for power supply agreements, ensuring transparency and cost-effectiveness. Additionally, the NEA monitors CSP compliance among ECs to ensure adherence to regulatory standards and promote efficient procurement practices, thereby enhancing the reliability and sustainability of rural electrification efforts.

The Philippine Competition Commission (PCC) is another independent competition authority. Founded in 2016, its mandate is to maintain market competition and penalise anti-competitive behaviour across sectors (PCC, 2024). There have been concerns regarding the respective jurisdiction of the PCC and the ERC in investigating and resolving anti-competition cases against market participants. The latest Supreme Court ruling in 2022 affirmed the ERC's mandate to investigate cases filed before 2015 (i.e. before the enactment of the Philippine Competition Act), but it remains unclear which institution will have jurisdiction in future cases (Juan, 2022). This could lead to a further backlog in the future, hampering the efficiency and credibility of the competition monitoring process in the power market and potentially impacting the affordability of electricity prices for consumers due to anti-competitive behaviour. The ERC has enlisted the PCC's support to initiate pending collusion cases filed before 2015, citing a lack of investigative capacity and know-how (Velasco, 2023). The Philippine Electricity Market Corporation (PEMC) was originally responsible for governing and operating the WESM. In 2018, as required under the EPIRA, responsibility for operating the WESM was transferred to the Independent Electricity Market Operator of the Philippines (IEMOP), while the PEMC continues to govern the WESM to ensure market competition and efficiency (PEMC, 2024b).

The IEMOP facilitates day-to-day electricity trading in the Philippines as the market operator of the WESM. It manages new registrations and market bids, forecasts demand, calculates real-time market prices, establishes dispatch schedules, monitors power trading and handles billing, settlement and collections. It also serves as the central registration body for the retail electricity market under the RCOA and the Green Energy Option Program (GEOP), wherein it enables contestable customers to procure electricity from licensed suppliers of their choice. Upon fulfilment of certain conditions precedent, the IEMOP will also assume the registrar function for the renewable energy market (REM) where renewable energy certificates (RECs) are traded, for confirmation with the PEMC (IEMOP, 2024).

The generation segment is almost entirely privatised. The Power Sector Assets and Liabilities Management Corporation (PSALM) was established under the EPIRA to manage the privatisation of publicly owned generation and transmission assets. The funds generated from these sales were used to liquidate the National Power Corporation's (NPC) financial obligations, contributing to a reduction of the country's consolidated public sector deficit. To this day, PSALM collects a charge from all consumers in electricity bills to service the NPC's stranded debts (PSALM, 2024a.; RA 9136).

The NPC, a government-owned and -controlled corporation, is the erstwhile public owner and operator of all power sector assets in the vertically integrated system. Since the introduction of the EPIRA, it has had a significantly reduced mandate limited to overseeing the electrification of certain islands and areas in the archipelago – through its Small Power Utilities Group (SPUG) – that are not yet connected to the national transmission grid. It also has responsibility for watershed and dam management through its rehabilitation and protection programmes and operates the two remaining publicly owned hydroelectric power plants in Mindanao (NPC, 2021).

The National Grid Corporation of the Philippines (NGCP) has been the Philippines' transmission system operator (TSO) since 2007. It operates on a 50-year concession contract. The NGCP is a private consortium of three companies, with 60 percent of the shares jointly owned by Monte Oro Grid Resources Corporation and Calaca High Power Corporation and 40 percent owned by the State Grid Corporation of China (NGPC, 2024a). As the TSO, the NGCP is responsible for operating, maintaining and developing the power grid, ensuring non-discriminatory access of market players to the transmission system and preparing the Transmission Development Plan subject to ERC regulations (NGPC, 2024a).

The National Transmission Corporation (TransCo) owns all transmission assets. It was established under the EPIRA to assume the electrical transmission assets and functions of the NPC until such time as a suitable private concessionaire could be found (RA 9136). According to the law, ownership of all transmission assets is to remain with TransCo. Since the concession agreement with the NGCP, TransCo's main responsibilities include ensuring the NGCP's compliance with regulations and administering the Feed-in-Tariff Allowance (FIT-All) Fund for renewable energy generators (TransCo, 2024) under the FIT programme and the GEAP.

# Market structure

The legacy of a market structured around baseload coal-fired power plants has delayed the installation of cheaper renewable energy technologies such as solar and wind power. Flexibility procurement has also been limited to date. Excess baseload capacities and high market concentration, with just a few players dominating supply, exacerbate the problem.

**Table 8. › Overview of the main features of market design in the Philippines**

| Category | Market design element | Description |
|---|---|---|
| **General** | Power system organisation | 1) Mandatory gross pool wholesale energy market;<br>2) bilateral contracts market (PSAs); 3) retail market |
| | Vertical integration | Unbundled – cross-ownership allowed between generation and retail |
| **Wholesale** | | - Mostly decentralised, private agents<br>- Centralised procurement through auctions for RE |
| | Wholesale electricity procurement | - Bilateral contracts: power supply agreements (PSAs)<br>- Spot market: wholesale electricity spot market (WESM) |
| **Retail** | Electricity dispatch | Centrally through WESM (mandatory gross pool) |
| | Reserves and ancillary services | Reserves market – co-optimisation of energy and reserves |
| **RE** | Participation of demand | Partly – only large consumers (DCC). Demand participation in the market is under development |
| | Consumer choice | Yes, after a peak consumption threshold – Retail Competition Open Access (RCOA) & Green Energy Option Program (GEOP) |
| | Demand response incentives | - Demand aggregation<br>- Time-of-use tariff (optional) |
| | Target | 35% of RE in power mix by 2030, 50% by 2040 |
| | Key RE policies | - RE auctions (GEAP)<br>- Renewable Portfolio Standards (RPS)<br>- Green Energy Option Program (GEOP)<br>- Distributed Energy Resources (DER) rules<br>- Priority of dispatch<br>- Enhanced net-metering |

### Power sector liberalisation

The electricity sector was unbundled and privatised in the 1990s to address utilities' rising debt burden. The reforms aimed to mobilise the private sector to bridge the infrastructure investment gap left by the state-owned National Power Corporation (NPC).

More than 20 years after the enactment of the Electric Power Industry Reform Act (EPIRA), private entities play a dominant role across the value chain. Despite mandatory unbundling, the regulations continue to allow some degree of cross-ownership between the generation, distribution and retail segments within the limits established by the EPIRA. Specifically, a distribution utility (DU) can obtain up to 50 percent of its total demand from affiliated generation companies. This has led to a trend towards vertical re-integration in the generation and distribution sectors. For example, major DUs such as the Manila Electric Company (Meralco) have expanded their participation in the generation and retail segments (Rudnick & Velaquez, 2019).

Power Sector Assets and Liabilities Management (PSALM) assumed ownership of all assets of the National Power Corporation with a mandate to privatise them. PSALM has privatised 32 generating assets and seven IPP contracts, totalling 8 861 MW – more than 30 percent of current installed capacity. As of 2024, four generation assets and two IPP contracts (less than eight percent of current installed capacity) remain state-owned and subject to privatisation (DOE, 2024; PSALM, 2024b).

***Ownership and market share***

Baseload fossil fuel power plants dominate the generation fleet, fuelled mainly by imported coal. As of November 2023, the total installed capacity in the Philippines was 28.3 GW, mostly consisting of fossil fuel-fired power plants (44 percent coal, 14 percent diesel and 13 percent natural gas). Renewable energy sources – mainly hydropower and geothermal power – contributed the remaining 29 percent. Solar and wind combined represent less than seven percent of total installed capacity (DOE, 2024).

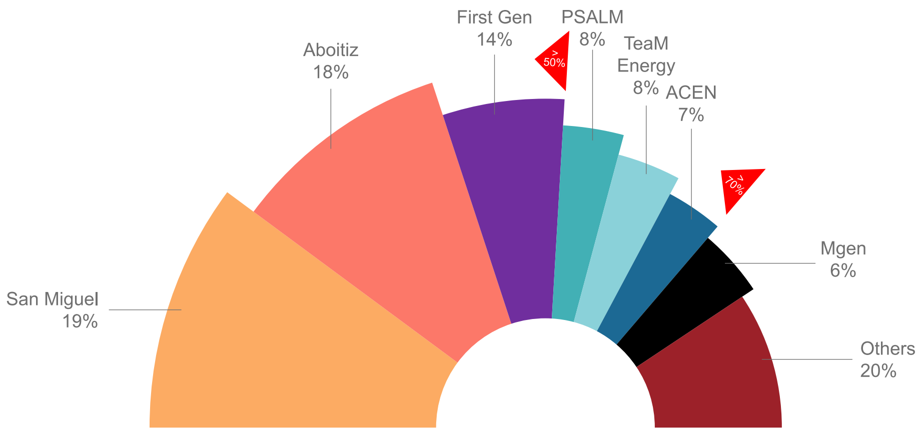
Luzon is home to 70 percent of the country's installed capacity, two thirds of which is fossil fuel-based. 16 percent of total installed capacity, predominantly coal and hydro, is to be found in Mindanao. Lastly, Visayas has 14 percent of the country's installed capacity, half of which is RE-based, mainly geothermal. Solar and wind installations are primarily situated in Luzon. Peak demand reached 16.6 GW in 2022, with an average annual growth rate of 4.5 percent over the last five years (DOE, 2024)[12].

The Philippine power system is configured almost exclusively around inflexible coal-fired generating capacity. In the last few decades, the country has experienced a rapid expansion of its baseload capacity, driven by a regulatory framework that prioritises these technologies. According to the Department of Energy (DOE), 80 percent of the country's baseload capacity is inflexible (Velasco, 2019).

The excess of baseload generation capacity strains and delays the uptake of new RE plants, mainly wind and solar. Despite high reserve margins in different grids – of 35 percent, 44 percent and 82 percent in Luzon, Visayas and Mindanao respectively in 2022 – the system has experienced recurring power supply deficiencies since 2014 (DOE, 2024). High peak demand due to elevated temperatures and lower availability of hydropower capacity during the summer seasons has resulted in tight power supply conditions – though that's only part of the story. Recurrent forced outages of baseload (coal) plants have pushed capacity below the predicted levels (ICSC, 2024). Today, inflexible baseload capacities deliver most of the power supply in the Philippines, yet these assets are unable to address peak demand requirements, resulting in power supply deficiencies, persistent high spot market prices and, periodically, rotating outages among end users. This highlights the need for flexible and peaking generation capacity

[12] The figures presented here correspond only to grid-connected capacity in the three main grids (Luzon-Mindanao-Visayas system). The capacity in small islands, not connected to the main grid, account for about 1-2 percent of the total mix.

**Figure 13. › Market share per entity in the Philippines***




*Market shares were calculated with ownership data from each respective entity.

Private entities own most of the power generation assets in the Philippines. To prevent monopolistic practices in the sector, the Energy Regulatory Commission (ERC) imposes ownership limits to restrict a single owner from controlling more than 30 percent of the generating capacity within a single grid and 25 percent at the national level (Resolution 03-2023, 2023).

The power generation market remains relatively concentrated, with three entities owning more than half of the capacity and a handful of major private producers – including San Miguel, Aboitiz, First Gen, TeaM Energy and AC Energy – collectively holding more than 70 percent of the generation capacity (Figure 13)[13].

Despite regulations limiting the concentration of ownership in the generation segment, some risks of market concentration remain. Producers may try to capitalise on pricing mechanisms to exercise market power.  For example, companies may bid strategically with their portfolio of assets (i.e. with marginal power plants) to increase the inframarginal rents for price-taking assets. Such opportunities increase with market concentration and are more prevalent in concentrated sub-regions due to nodal pricing.

## Transmission and distribution

The transmission grid in the Philippines is divided into three electrical systems: Luzon, Visayas and Mindanao. These systems are interconnected by a network of high-voltage direct-current (HVDC) lines and submarine cables, enabling the transfer of electricity between regions. The completion of the Mindanao-Visayas Interconnection Project (MVIP) in 2023 marked the final step in interconnecting all three grids, with Mindanao being the last to be integrated into the main power system. Power flows are scheduled through the wholesale electricity spot market (WESM) that was established in Luzon in 2006, expanded to the Visayas grid in 2010 and to the Mindanao system in 2023 (PEMC, 2024b).

The Philippines has two types of distribution system operators (DSOs) – distribution utilities (DUs) and electric cooperatives (ECs). DUs are privately owned utilities that mainly operate franchises in densely populated urban areas where competition is viable.

ECs tend to be small area-based non-profit entities providing electricity to rural areas. There are nearly 120 ECs in the Philippines, governed and supported financially and technically by the National Electrification Administration (NEA) to procure greenfield RE capacity – including rooftop solar – through power supply agreements (PSAs). NEA supports rural electrification by acting as a guarantor to the ECs for their purchases on the WESM to support their creditworthiness (NEA, 2023).

[13] Market share was calculated on the basis of the information on ownership posted on the website of each respective entity.

Distribution utilities and electric cooperatives are both responsible for distributing electricity to their respective franchise areas (i.e. DSOs) and are subject to the ERC's regulations and ratemaking under the Electric Power Industry Reform Act (EPIRA). They are required to procure and supply electricity to their captive markets in a least-cost manner. There are over 150 DSOs registered with the DOE, though 55 percent of the market share is held by one DU: the Manila Electric Company – Meralco (Meralco, 2024b).

The remuneration of TSOs and DSOs is regulated according to a cost-of-service regulation model. The ERC regulates remuneration to the TSOs and DSOs, which allows them to recover their operational costs, maintenance expenses and capital investments, along with an approved rate of return. The transmission and distribution tariffs to cover their remuneration are included in the electricity rate, which is also set by the ERC (ERC, 2024; Resolution 08-2022).

***Electricity supply***

Electricity supply in the Philippines is structured around two types of consumers: contestable and captive consumers.

- Contestable consumers are end users with a monthly average peak demand of at least 500 kW. These consumers have the right to participate in the retail competition and open access (RCOA) market, whereby they can choose their retail supplier.

The ERC sets this threshold and has gradually reduced it from 1 MW to 750 kW and then to its current level of 500 kW (WESM, 2022). A proposal is currently under consideration to further reduce the RCOA threshold to 100 kW of average peak demand for one year to encourage retail participation, especially among households and small businesses. These adjustments need to be accompanied by process improvements designed to minimise barriers to entry (IEMOP, 2024).

A separate contestability threshold is defined in the Green Energy Option Program (GEOP) that allows consumers with an average peak demand of up to 100 kW to choose exclusively among RE suppliers. Two or more end users within a contiguous area are allowed to aggregate their demand and collectively reach the thresholds, entitling them to be treated as a single contestable customer and participate in the RCOA and GEOP.

Suppliers operate under distinct classifications: retail electricity supplier (RES), local retail electricity supplier (LRES) and supplier of last resort (SoLR). All suppliers within this segment are privately owned entities that need to be registered in the WESM but are not obligated to secure a franchise or obtain approval from the ERC for their pricing strategies, except for SoLRs, which are subject to regulatory oversight.

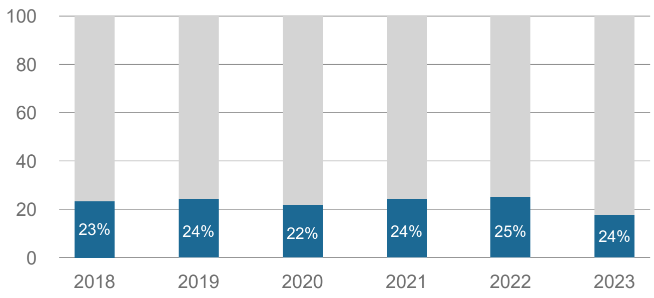
Captive consumers are end users whose aggregated demand in a contiguous area is below the threshold for contestable consumers (500 kW in RCOA or 100 kW in GEOP).

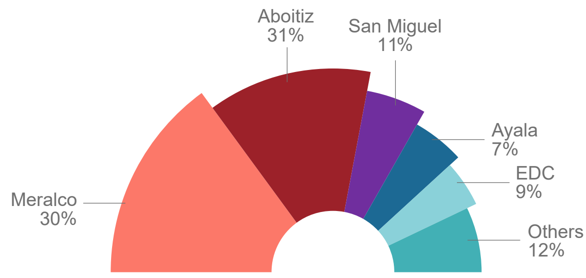
- Captive consumers are not able to choose their electricity suppliers but instead are supplied by default electricity suppliers as determined by the ERC, typically the DSO responsible for the franchise area in which the consumer is located.

Contestable consumers comprise approximately 24 percent of total electricity consumption in the Philippines, captive consumers account for about three quarters of total consumption and do not participate in retail competition (Figure 14) (PEMC, 2024e).

Despite nearly 80 retailers being registered in the RCOA, the retail market remains relatively concentrated, with a handful of suppliers having a market share of about 90 percent. Among these, Aboitiz and Meralco are the largest players, holding the highest percentage share of contestable consumers (31 percent and 30 percent respectively), which underscores their dominance in the supply market (DOE, 2024; PEMC, 2024e).

**Figure 14. › Electricity consumption per consumer segment (left) and share of the contestable market per entity (right), 2018-2023**




Source: PEMC, 2024e.

Directly connected customers (DCCs) – bulk customers connected to the transmission grid – can participate in the spot market (e.g. opt for demand bidding or somewhat inelastic participation) and voluntarily engage in bilateral contracting with electricity producers. DCC account only for a marginal two percent of registered contestable consumers.

## Investment regulations and market openness

Recent policy measures have removed ownership restrictions on renewable energy projects. Challenges persist, however, including cumbersome permitting procedures and inadequate transmission infrastructure, requiring further improvements to ensure the sector's sustained growth and investor confidence.

The Philippines ranks 95 in the Ease of Doing Business index because of bottlenecks in start-up ease, contract enforcement and access to credit (World Bank Group, 2024). In the FDI Regulatory Restrictiveness index, the Philippines ranks among the lowest due to local content measures, foreign ownership restrictions and minimum paid-up capital requirement (OECD, 2024a).

Fostering privatisation and market competition, the Electric Power Industry Reform Act (EPIRA) created new investment opportunities in the power sector. In November 2022, this was further strengthened by an amendment to the Renewable Energy (RE) Act of 2008 which removed foreign ownership restrictions on the exploration, development and utilisation of solar, wind, hydropower, ocean and tidal energy resources (Koty, 2023; Ocampo & Suralvo Law Offices, 2022; Quintero et al., 2022). The amendment applies to both new and existing projects, allowing foreign investors to acquire shares from their local counterparts. 100 percent foreign ownership of other renewables like biomass, waste and geothermal had already been possible since 2020. Notably, this policy change does not apply to the distribution and transmission sectors, which maintain their "public utility" classification and restrict foreign ownership to 40 percent.

The removal of foreign ownership ceilings on new renewable energy projects is set to support VRE investment in the Philippines. The government could consider embedding this policy in a broader industrial strategy that avoids adverse implications from the perspective of a just energy transition, supporting local value creation, job creation and local capacity development. In addition, such policies should be accompanied by safeguards that factor in consumers' exposure to price risk from inflation and exchange rate fluctuations. Safeguards must be in place to ensure that foreign companies, besides installing renewable technologies, contribute to the development of the local community and economy.

Moreover, RE investments benefit from the government's strategic investment promotion initiatives. For instance, the Green Lanes programmes launched in February 2023 aim to improve the ease of doing business in the country for selected strategic investment areas (including RE) by streamlining regulatory processes (Ayeng 2024; EO 18). Additional fiscal incentives are available for renewables under the RE Act (see Policy instruments for VREs).

Although the framework adjustments facilitate VRE investments, implementation remains a bottleneck. Licensing and permitting procedures for RE projects are reported to be cumbersome, time-consuming and uncertain. In 2019, the Department of Energy (DOE) established the Energy Virtual One Stop Shop (EVOSS) to streamline permitting procedures, which was successful in reducing permitting lead time by about 100 days. However, further measures are needed to ensure consistency of permitting requirements, coordination across government institutions, clear and definite decision-making timelines and durability of awarded permits.

Grid connection poses another challenge to investors. The rollout of new transmission and connection infrastructure, as envisaged by the annual transmission development plans of the National Grid Corporation of the Philippines (NGCP), is often delayed. This has resulted in a backlog of grid connection applications that have increased the transaction costs of RE deployment. Similarly, the process of securing grid connection permits is cumbersome and time consuming. Consequently, developers face uncertainty about when their assets can start delivering power to the grid and often have to install transmission infrastructure at their own cost. Meanwhile, the grid code is ambiguous about the conditions under which developers can have the costs of (common user) grid infrastructure reimbursed. This has affected the financial viability of RE investments (OECD, 2024b).

## Policy instruments for VREs

The Philippines has introduced several policy mechanisms to support the deployment and development of RE in its efforts to achieve 35 percent renewables in the energy mix by 2030 and 50 percent by 2040. These targets aim to reduce reliance on imported commodities such as coal and enhance the country's energy security.
The RE Act of 2008 (No. 9513) established a legal framework for renewable energy support instruments. Table 9. Renewable energy support instruments in the Philippines lists the support measures currently in use.

**Table 9. › Renewable energy support instruments in the Philippines**

| Supply-side measures | Demand-side measures |
|---|---|
| Renewable Portfolio Standards (RPS) | Green Energy Option Program (GEOP) |
| Green Energy Auction Program (GEAP) | Net metering |
| Priority dispatch for renewables | Distributed Energy Resources (DER) Rules |

In 2020, the government announced a moratorium on new coal-fired power generation projects as part of its commitment to curb reliance on inflexible fossil fuel-based electricity generation. However, previously approved coal projects will proceed as planned. Since the enactment of the Electric

Power Industry Reform Act (EPIRA) in 2001, the Philippines has removed the majority of fossil fuel subsidies in the electricity sector. This has helped level the playing field between fossil fuels and RE.

### Feed-in Tariff (2012–2019)

Enacted in 2012, the Feed-in Tariff (FIT) was an early mechanism to incentivise private investment in RE. Covering various technologies such as hydro, wind, solar, ocean and biomass, the FIT programme set capacity targets for each technology. It guaranteed RE developers a fixed price (in Philippine pesos per kilowatt-hour (PhP/kWh)) for electricity generation over a 20-year period. This fixed price was passed on to all end consumers as a separate uniform charge socialised in the electricity rate, known as the Feed-in Tariff allowance (FIT-All). For more details about FIT-All, see the tariff structure in the Market  section.

Despite its initial success, the FIT programme faced challenges, including concerns about its perceived impact on electricity tariffs. Additionally, the FIT programme involved stringent requirements regarding project readiness and installation targets, with projects that failed to meet these benchmarks risking exclusion from FIT eligibility. This posed significant financial risks for developers, potentially leading to stranded assets or exposure to merchant risk in the wholesale electricity spot market (WESM) for those unable to secure FIT status. The instrument was discontinued in 2019 (except for run-of-river hydropower) and succeeded by the Green Energy Auction Program (GEAP) in 2021.

### Renewable Portfolio Standards (RPS)

The government introduced a (consumption-based) Renewable Portfolio Standard (RPS) programme in 2017. The RPS requires distribution utilities (DUs), electric cooperatives (ECs), retail electricity suppliers (RES) and generating companies serving directly connected customers (DCC) to source a specified percentage of their annual supply from eligible RE sources (PEMC, 2024c). RPS obligations are tied to RE targets. Those entities covered are subject to penalties if they fail to comply with RPS requirements.

The RPS is accompanied by the Renewable Energy Market (REM), inaugurated in 2022, which enables participants to trade Renewable Energy Certificates (RECs). One REC equals one MWh of electricity generated from eligible RE plants built in or after January 2009. Compliance entities use RECs to meet their annual RPS obligations. Besides utility-scale RE plants, behind-the-meter sources are also eligible to generate RECs. The procurement of RECs is envisaged as a last resort for DUs/ECs, which are encouraged to generate RECs directly by investing in renewables or by procuring renewable energy on the market. The owners of distributed energy resource (DER) assets sell RECs via their host distribution utility. The REM, under the administration of the market operator – the Independent Electricity Market Operator of the Philippines (IEMOP) as of 2023 – monitors compliance with RPS obligations.

In April 2024, the Energy Regulatory Commission (ERC) published a REC price cap (Resolution 08-2024). The calculated REC price cap is PHP 241.56/MWh. This is calculated by the ERC according to the missing money principle, i.e. the weighted average difference between the ERC-approved rate for RE power supply agreements (PSAs) and the weighted average electricity price (ERC, 2024).

**Stakeholders have identified several challenges to the RPS:**

- ► Uncertainty about the remuneration of RECs may create additional risks for renewables, potentially impacting their financial costs.
- ► Uncertainties regarding the availability of sufficient RE capacity to enable compliance entities to fulfil their RPS obligations.
- ► The complexity of burden sharing associated with the distribution of RECs among various DUs with different percentages of RE.
- ► Implementation hurdles faced by smaller participants reliant on fewer contracts.

**The following measures could be considered to improve the RPS' effectiveness:**

- ► Expedite RE deployment such that 1) REC supply meets RPS obligations and 2) RPS obligations can be ratcheted up. In 2023, the minimum annual increment of the RPS requirement increased from one percent to 2.5 percent under the RPS main grid rules.
- ► Make REC prices public in order to increase the transparency of the RPS and reveal its investment signal.
- ► Introduce operational or financial instruments (on top of the REC price cap) to keep REC prices stable, reducing the market risks associated with their volatility.
- ► Mitigate barriers that make it difficult for DUs with smaller RE shares or small participants to access RECs, e.g. by contracting RE capacity by means of the opt-in mechanism of the RE auctions (see below).

### Green Energy Auction Program (GEAP)

The Green Energy Auction Program (GEAP) is the Philippines' main procurement instrument to deploy variable renewables. Launched in 2021, the GEAP marked a shift from the previous feed-in tariff to competitive RE procurement. The GEAP aims to capitalise on global cost declines in VREs, minimise offtake risks, improve project bankability and reduce electricity costs for end consumers. The auction programme provides long-term revenue certainty for capital-intensive VRE projects, enabling them to attract private-sector investment. The GEAP awards winning bids a power supply agreement (PSA) with the National Transmission Commission (TransCo). Overall, the GEAP has increased the transparency of renewable energy procurement with a pipeline of projects that can be scaled in line with RE targets. The new generation capacity that enters the grid through auctions furthermore supports compliance entities' obligations under the RPS through increased supply of RECs.

***Design elements of the GEAP***

- Auctions are structured around renewable technology and grid capacity targets that are set by the Department of Energy (DOE). Participation in the auctions is open to solar (ground-mounted, rooftop, floating), onshore wind, biomass and run-of-the-river hydropower. RE capacity targets are determined by current and future grid capacity requirements, RE targets and the volume of RECs available in the market to meet RPS requirements.
- **The auctions target greenfield investment in renewables** and include expansions or upgrades of existing facilities.
- **A ceiling price caps participants' bids in a reverse auction.** Participants submit bids for capacity, price and expected commissioning date, which the DOE aggregates by technology and grid system and ranks from lowest to highest price until the capacity target is reached (DC 2021-11-0036).

- **Winning bids are awarded a 20-year PSA on a pay-as-bid basis**, denominated in PhP/kWh. RE generation has priority dispatch in the WESM. A shift to pay-as-clear auctions is under consideration.
- **End users act as offtakers for the winning projects of the GEAP.** TransCo collects the money from end consumers using the FIT-All component of the tariff and facilitates payments to awarded RE developers (see tariff section).
- **The opt-in mechanism aligns the GEAP with the RPS.** Eligible RPS-mandated participants can use the opt-in mechanism to directly procure renewable energy from the GEAP pool of winning bidders, helping them comply with RPS requirements and reducing the FIT-All charges for end users (see Box 10 below). Utilities rather than TransCo are then responsible for recouping the renewable energy costs.

**Box 7. › Opt-in mechanism within the GEAP in the Philippines**

The design of the Green Energy Auction Program (GEAP) includes an opt-in mechanism, a policy aimed at articulating auction results to broader segments of the electricity market, including compliance with the Renewable Portfolio Standard (RPS) and its effects on the electricity tariff to end consumers.

The opt-in mechanism allows distribution utilities (DUs) to procure renewable energy directly from the GEAP auctions. The objective is twofold: to decrease the Feed-in Tariff Allowance (FIT-All) rate charged to end users in the electricity tariff, and to help mandated participants meet their RPS requirements.

**How it works**

Eligible participants (DUs, RES and GENCOs with DCC) can choose to directly procure renewable energy capacity from the pool of winning bidders in a GEAP auction round. The opt-in capacities are considered to be compliant with the competitive selection process (CSP) requirement for DUs and support them in meeting their respective RPS obligations.

The opt-in has implications for end users. By opting in, the procured energy is deducted from the FIT-All compensation system, thereby reducing the basis on which the FIT-All component of the electricity tariff is calculated for all end consumers. The opt-in volume is then charged to the relevant DU’s captive consumers in the generation charge instead of being socialised in the FIT-All component of the electricity tariff (see tariff section). The price of the opt-in capacity is calculated as the weighted average price resulting from the auction round.

Effectively, the successful bidder continues to receive their bid price after the opt-in is executed. However, it transfers the offtake obligations from TransCo to DUs.

With this mechanism, the Philippines hopes to create a more flexible and cost-effective system for renewable energy procurement, ultimately aiming to reduce costs to end consumers and increasing renewable energy adoption.

Source: DC 2023; DC 2023-00-000; Flores, 2023; Velasco, 2023a; Velasco 2023b

***Hurdles and opportunities of the GEAP***

After two auction rounds, the GEAP has accelerated the deployment of renewables. While the first round was fully subscribed, the second round, despite having auctioned more volume, fell far short of its target – awarding less than 30 percent of the planned capacity. The two rounds combined have awarded contracts for a total of 5.4 GW of RE capacity, equivalent to 65 percent of the total installed RE capacity in the Philippines by the end of 2023.

**Stakeholders have pointed out several hurdles that dissuaded participation in the GEAP:**

► **Limited transmission grid capacity:** Insufficient grid infrastructure investment has delayed the commercial operation date of VRE projects awarded in the auctions and limited the number of otherwise feasible projects.

► **Low price ceilings:** Many potential participants considered the price ceilings set by the ERC to be too low. The technology-specific price ceilings were set at PhP 4.8738/kWh for rooftop solar, PhP 4.4043/kWh for ground-mounted solar, PhP 5.3948/kWh for floating solar, PhP 5.8481 /kWh for wind and PhP 5.4024/kWh for biomass. These were lower than the old FIT tariffs by almost 50 percent in the case of solar, 20 percent in the case of wind and 13 percent in the case of biomass, reflecting a decrease in technology costs. Notably, the ceiling prices were not differentiated by location and project size, which could affect the viability and risk exposure of different projects due to their scalability and resource availability.

**The following measures could be considered to improve the auctions and increase their subscription:**

► **Widen the scope of the auctions** to cover other technologies that contribute to the energy transition. These include dispatchable RE technologies (geothermal and impounding hydropower) and energy storage (BESS and pump-storage hydro). By broadening the scope, auctions could take advantage of complementarities between regions' resources and increase deployment rates.

► **Improve transparency** on how the auction capacity targets are determined for each technology. The study used as the basis for determining the RE targets underlying the auction should be subject to public consultations.

***Broader impacts of the GEAP***

- The GEAP spurs deployment of variable renewable energy sources into the mix, which promises to reduce energy costs over time. However, greater VRE shares are required for this effect to become noticeable. On the other hand, power supply agreements for baseload fossil producers lock in costs for many years, which may prevent the additional deployment of VREs from immediately translating into lower tariffs. Payment obligations to fossil-fuelled assets in power supply agreements need further attention (see Market and contractual arrangements).
- The GEAP and RPS are complementary in advancing the adoption of RE in the country. From a policy perspective, the GEAP and RPS are coordinated with respect to volume and price. The energy generated by RE facilities awarded in the GEAP increases REC supply for RPS compliance.

### Priority dispatch of RE

Priority dispatch of renewables aims to increase the use of RE in the energy mix. This initiative consists of two categories: 1) Must dispatch covering VREs (e.g. wind and solar), and 2) priority dispatch, covering other REs, after the must-dispatch plants. Initially introduced in 2016, the must-dispatch status was granted to wind, solar, run-of-river hydro and ocean energy, irrespective of FIT eligibility. Additionally, biomass under FIT received priority dispatch status. In 2023, the regulations were amended to include geothermal and impounding hydro within the priority dispatch category.

### RE support mechanisms for end users

There are two RE support mechanisms targeting end consumers: the Green Energy Option Program (GEOP) and net metering. The GEOP, established under the RE Act of 2008, allows end consumers to voluntarily source their electricity from renewable sources and negotiate electricity prices directly with RE suppliers. Participants eligible for the GEOP include entities with an annual average peak demand of at least 100 kW, which is considerably lower than the threshold of 500 kW to participate in the retail competition and open access (RCOA). While the programme officially commenced operations in 2022, the GEOP is not widely promoted and its uptake has been limited (PEMC, 2024d).

On the other hand, a net metering mechanism incentive applies to end users for behind-the-meter solutions with capacities up to 100 kW. This mechanism also allows users to sell surplus power they have generated back to the grid, providing an additional source of revenue. Net metering offers a flexible and accessible way for consumers to participate in renewable energy generation while potentially reducing their electricity bills.

### Fiscal incentives

The fiscal incentives provided under the RE Act of 2008 encompass various measures aimed at promoting investment and development in the renewables sector (Orbitax, 2022). These incentives include an income tax holiday of up to seven years from the start of commercial operations for both existing and new RE projects. Additionally, developers can benefit from net operating loss carry-over (NOLCO) provisions, allowing losses incurred during the initial three years of operation to be carried over as deductions for the subsequent seven years. After the income tax holiday period, RE developers are subject to a reduced corporate tax rate of ten percent, provided that the associated savings are passed on to end users in the form of lower electricity rates. Accelerated depreciation is also available if the income tax holiday is not granted before full operation, enabling developers to depreciate plant and equipment at an accelerated rate and thus pay lower taxes.

Furthermore, the fiscal incentives include a zero percent value-added tax rate for various activities related to RE. This includes the sale of renewable electricity, ancillary services supporting the integration of RE and the purchase of goods and services necessary for RE development and installation. Moreover, proceeds from the sale of carbon emission credits are exempt from taxation.

## Market and contractual arrangements

Power supply agreements (PSAs) for fossil baseload power are based on outdated regulatory principles that prioritise the expansion of baseload electricity generation with attractive terms that mitigate risks and prioritise these assets over flexible and clean energy sources. The market risk against which PSAs protect producers is ultimately transferred to end consumers, exposing them to high electricity costs and risks. Since PSAs for baseload assets stipulate capacity factors, they interact with the wholesale electricity spot market (WESM) – the centralised dispatch mechanism with mandatory participation. In doing so, baseload power PSAs distort market signals and hinder the efficiency of a sophisticated spot market well equipped to integrate higher shares of variable renewable energies.

Over-contracting by distribution utilities (DUs) compounds existing market inefficiencies. Most DUs choose to procure energy bilaterally as a hedge against price volatility and uncertainty on the spot market. The volume of bilaterally contracted energy is fixed over long periods – based on capacity (e.g. peak demand)

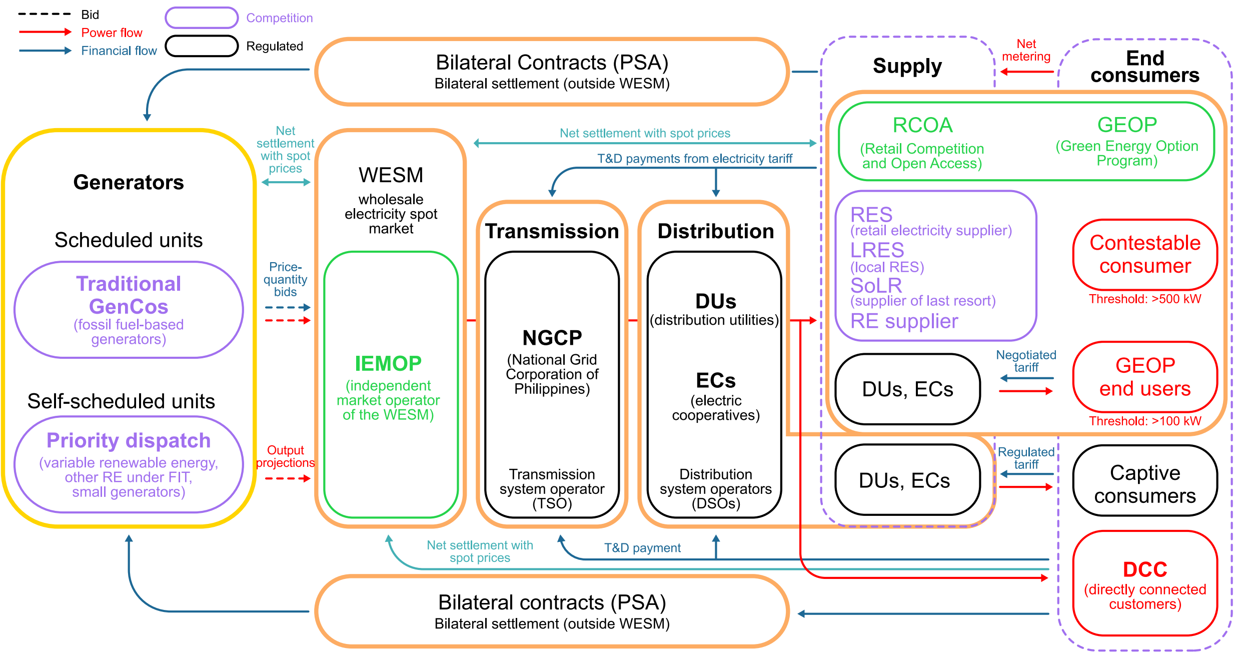
– while actual energy consumption changes hourly. As a result, DUs may end up procuring excess energy during off-peak hours while being exposed to the WESM during peak demand periods (see section "Impact of DUs' over-contracting strategies" for more details).

**Power trading arrangement overview**
Electricity is traded through two main mechanisms in the Philippines: bilateral contracts and the WESM. The WESM consists of a mandatory gross pool market for short-term dispatch with detailed bidding formats and high temporal and spatial granularity. The WESM requires all generators connected to the grid to be registered and dispatched via the market, regardless of the contractual positions of the trading participants.

By contrast, bilateral contracts, in the form of PSAs, are long-term contracts between generation companies and DUs, ECs or RES with terms and conditions negotiated between the parties. Bilateral contracts are the main instrument for electricity trading.

These two mechanisms interact and interfere with one other. Though they serve different and ostensibly complementary purposes – where PSAs provide long-term revenue certainty for investments and the WESM optimises the utilisation of resources in the short term – the rules governing each and their overlapping nature have distorted market operations, hindering both instruments from effectively fulfilling their intended purpose.

**Figure 15. › Market functioning diagram of the Philippines**




***Bilateral contracts – power supply agreements***
Bilateral contracts are the main instrument for electricity trading in the Philippines. They aim to provide the long-term stability and risk management that are essential for planning and investment. In 2023, bilateral contracts accounted for approximately 83 percent of the total electricity traded in the country (IEMOP, 2024). These contracts are voluntary agreements between the parties that take the form of power supply agreements (PSAs), similar in form and function to power purchase agreements (PPAs). The terms and conditions of PSAs are negotiated bilaterally and may differ among parties, yet all PSAs require regulatory approval. Unlike transactions within the WESM, the amounts of electricity transacted in

bilateral contracts are financially settled between the parties outside it. While more than 80 percent of electricity is traded bilaterally, generators are dispatched through the WESM and must participate in it.

The key features of bilateral contracts vary according to the customer segment they aim to supply. Physical PSAs aimed at supplying captive customers – primarily households and commercial customers – by DUs or ECs operate under regulatory oversight. While the terms of these contracts are agreed upon bilaterally, they are subject to regulatory reviews and approval by the Energy Regulatory Commission (ERC).

**PSAs for the captive market are designed to guarantee full cost recovery and hedge baseload producers and suppliers against market risk, which is passed on to consumers.** PSAs for the captive market are bilateral contracts that DUs must secure to ensure power supply for their captive consumers. These agreements are subject to the DOE's competitive selection process (CSP), which is governed by guidelines set by the ERC. Under the CSP, DUs are required to solicit and evaluate bids from at least two qualified generation companies, adhering to the principle of technology neutrality. The PSAs are based on the utility's power supply requirements outlined in the DOE-approved power supply procurement plans, which govern the timing and amount of capacity to be procured the DUs and ECs. The ERC reviews and approves these agreements, ensuring transparency and competition in the procurement process (Resolution 13-2015).

With the latest revision of the CSP guidelines in 2023, PSAs for the captive market can now take various forms, such as financial PSAs, physical PSAs or PSAs with renewable energy plants, each with specific contract durations. Financial PSAs that are not tied to specific power plants have a maximum duration of ten years, while physical PSAs extend to up to 15 years. Those for RE plants may last up to 20 years (ERC, 2023). However, most of the PSAs in use today were concluded under the previous CSP guidelines, which did not distinguish between financial and physical contract types.

According to the ERC's guidelines, PSAs are designed to guarantee full recovery of generation costs. They include the following cost components, which DUs and ECs pass on via regulated electricity tariffs (ERC, 2014):

- Capacity costs (with an allowable rate of return on capital). Capital costs recognised in PSAs are typically amortised at a fixed rate throughout the contract, regardless of the actual energy supplied (ERC, 2014).
- Fixed operating and maintenance (O&M) costs.
- Variable costs, primarily fuel costs. PSAs include a feature involving automatic pass-through of fuel costs to consumers, with adjustments based on prevailing coal price indices.
- The remuneration scheme of these agreements can be adjusted according to load factors, where capacity remuneration increases when the generation plant is underutilised.
- PSAs may include minimum offtake obligations that obligate DUs to purchase a fixed amount of electricity regardless of actual demand.
- PSAs can be denominated in foreign or local currency. Generation costs are indexed to factors such as fuel prices, inflation and foreign exchange rates.

**Baseload PSAs were designed to meet rapid increases in electricity demand but are at odds with the requirements for a flexible and clean energy system.** Long-term PSAs are the main instrument to incentivise investments in new capacity additions, providing secure revenue streams whereby to finance them. However, the design of these contracts, and their regulatory approval, were conceived under fixed financial assumptions that favoured the expansion of low-cost generation in a baseload-centred system. PSAs for the captive market are not adapted to the evolution of a competitive electricity market or the growing need for flexible and clean generation (Ahmed et al., 2021). In their current form, PSAs insulate fossil fuel power plants from transition risks and shift the cost of inefficient utilisation of the coal fleet to end consumers.

In a competitive market environment, generators reflect increased costs in their offer prices but do so at the risk of reducing their market share if lower-cost supply sources become available over time. The current design of PSAs shields producers from such market (or dispatch) risk, guaranteeing full cost recovery. PSAs increase capacity payments to baseload assets when these are not utilised, be it due to lower than projected demand, non-dispatch for economic or flexibility reasons or displacement by low-cost renewables. The additional cost this imposes on the electricity system is ultimately borne by ratepayers.

**PSAs ensure supply security for captive consumers but fall short of guaranteeing affordable electricity.** Over-procurement of baseload (coal) power on the back of attractive PSAs has locked capacity costs into the system. Meanwhile, the increasing reliance on coal-fired power has exposed the power system to short-term fuel price shocks. The DOE's competitive selection guidelines and PSAs for baseload generation transfer these risks (i.e. underutilisation and fuel price volatility) to ratepayers. While end consumers are fully exposed to market risk, they are less well equipped to respond to it. The global energy crisis of 2021-2023 underscored the affordability impacts on end consumers in the Philippines. In parallel to drastically reducing the reliance on coal, the risk allocation between producers, offtakers and consumers in existing PSAs needs to be revisited.

The skewed allocation of risks and costs affects energy affordability and creates perverse incentives for market players. It falls on the regulator to safeguard energy affordability, protect consumers from excessive price risk and ensure equitable risk allocation.

**PSAs have contributed to an overbuild in coal power capacity with attractive de-risking measures that do not extend to variable renewables.** In 2022, 58 percent of total electricity production came from coal plants following two decades of rapid capacity expansion. According to the DOE, 80 percent of the country's baseload capacity is inflexible (Velasco, 2019). While PSAs for fossil fuel plants incorporate revenue compensation for underutilisation – similar to minimum offtake obligations – those for renewable energy plants are structured with fixed prices that are adjusted only for inflation. Fossil fuel power plants also recover their capital costs at a fixed rate throughout the contract. The unequal risk/cost coverage for fossil-based and renewable technologies must be addressed to level the playing field for investment and spur renewables deployment.

**CSP guidelines and PSAs do not encourage generating companies and utilities to adopt efficient risk management strategies and procurement practices.** By transferring risks to consumers, the current design of PSAs undermines incentives for DUs to procure electricity supply at least cost. As a result, utilities are not motivated to hedge against factors such as inflation or US dollar exchange rate volatility, despite the potential impact of these fluctuations on procurement costs (Ahmed et al., 2021). Minimum offtake obligations further constrain DUs in diversifying their short- to mid-term procurement strategies. The lack of proactive risk management exposes consumers to financial risks and uncertainties, as any adverse developments in fossil fuel markets and the national power market are passed on to ratepayers.

Following concerns about rising coal import dependency, the DOE announced a moratorium on new coal-fired power plants in 2020 (DOE, 2020). Additional measures are needed to ensure that 1) existing fossil fuel assets impose less costs on the system; 2) these assets can be operated more flexibly and; 3) incentives are in place to procure flexibility alongside increased VRE capacity. While the design of instruments is beyond the scope of this evaluation, the following opportunities could be considered:

- **Complement the coal moratorium with incentives to drive procurement of the flexible capacity needed to integrate higher shares of VREs in the coming years,** for example through flexibility procurement auctions alongside the GEAP.
- **Incorporate carve-out clauses in standard PSAs** allowing suppliers to reduce capacity payments or the amount of power they must take from inefficient and underutilised coal-fired power generators. These clauses would reintroduce a degree of market risk for power producers. Only Meralco included carve-out clauses in its PSAs – other DUs/ECs did not have these clauses in the past (Fairhurst, 2017; Ahmed & Dalusung III, 2020; ADB, 2021). With the introduction of new competitive selection process guidelines at the end of 2023, carve-out clauses are now required for all DSOs (Resolution 16, series of 2023, (ERC, 2024)).

### The wholesale electricity spot market (WESM)

The WESM is the platform for short-term electricity trading between large-scale buyers and sellers, and the market mechanism for electricity dispatch in the Philippines. Initially launched in Luzon in 2006, then in Visayas in 2010 and subsequently expanded to Mindanao in 2023, the WESM has progressively broadened its geographic coverage as grid interconnections throughout the country have increased. The WESM operates as a mandatory gross pool market. It features a price-based bidding system that allows participants to adjust their offer prices to optimise their trading position ahead of gate closure.

#### *Market characteristics*

The WESM requires all entities connected to the grid to be registered and all electricity in the system to be dispatched through the market regardless of the contractual positions of the trading participants. Generators must offer all available capacity on the spot market to be dispatched. Bilateral contract quantities are financially settled outside of the WESM, and only spot quantities – i.e. generation or consumption above contracted quantities – are settled at spot prices.

WESM is a one-sided pool market in which generation companies (GENCOs) are the main participants. While distribution utilities (DUs) and retail electricity suppliers (RES) have been passive participants in the WESM so far, providing the market operator with inelastic consumption forecasts, the WESM is planned to transition to a two-sided pool market to allow demand-side bidding.

Market participants in the WESM are divided into categories for consumers and GENCOs (Figure 15). Consumer categories include DUs, RES and directly connected customers (DCC). On the other hand, GENCOs are categorised as scheduled generating units or three types of self-schedule generating units. Scheduled generating units are traditional large dispatchable GENCOs (e.g. fossil fuel-based generators), while self-schedule generating units include non-scheduled generating units (small generators), must-dispatch generating units (VRE generators) and priority-dispatch generating units (other RE GENCOs such as biomass, geothermal and hydro under the FIT system) (IEMOP, 2021).

The WESM runs on a sophisticated market dispatch model that co-optimises energy dispatch and reserve allocation, with high spatial and temporal granularity and detailed grid representation. The market clearing results in scheduling decisions for all market participants, energy flows in the grid and local marginal prices calculated for each node at five-minute dispatch intervals.

#### *Functioning of the WESM*

The WESM employs a security-constrained economic dispatch (SCED) model that takes transmission constraints, losses and the technical characteristics of the power system into account to determine the dispatch schedule for each five-minute trading interval. By jointly optimising energy and reserves, the WESM schedules generation assets in a cost-optimal manner while ensuring grid stability. The market operator (MO) forecasts demand and acquires grid information from the system operator (SO) in order to match generation offers with projected demand, resulting in a dispatch schedule; the MO also reserves allocation and electricity prices per node (i.e. locational marginal prices, LMP) (WESM, 2021a; WESM, 2021b).

In 2021, the WESM moved from an hourly to a five-minute trading interval, allowing for more accurate and flexible operation of the market. For each trading interval, participants submit market offers and bids to sell or buy electricity at specified prices (negative price bidding is allowed). As a gross pool, all large dispatchable generation units are required to offer all their capacity and submit price offers linked to it. Non-dispatchable generation units – including very small units, VRE and priority dispatch units – submit generation forecasts without prices. A recent adjustment to the market rules eliminated a previous requirement for generators to define a minimum output constraint in their quantity bids. Consequently, generators bid from zero capacity and any minimum technical generation constraints must be included in the offer prices for each capacity block.

**The dispatch process operates with consecutive timeframes, allowing participants to adjust their bids from one week in advance to minutes before real-time operations.** The dispatch process includes week-ahead and day-ahead projections, offering indicative hourly dispatch schedules and spot prices for the next day up to seven days ahead. Additionally, hour-ahead projections offer schedules for every five-minute interval in the following hour. Gate closure occurs nine minutes before real-time delivery, allowing trading participants to submit or update self-scheduled nominations, bids or offers right up until this point. Real-time dispatch (RTD) schedules are then determined according to the dispatch optimisation model, providing energy and reserve schedules for each five-minute interval. Once the RTD schedules have been determined, the system operator implements them for each dispatch interval and ensures compliance.

**Market clearing prices in the WESM are determined by the marginal offer price to meet the demand in a given interval for each node in the network, reflecting losses and congestion in the transmission grid.** Similarly, reserve prices are calculated for each reserve region. In addition, the market design incorporates price intervention mechanisms to address extreme price spikes or sustained high prices in the market (WESM, 2021b).

Looking ahead, two major reforms are being considered to improve market functioning. Rules for demand-side bidding have been under development since 2021. Implementing this initiative requires commercial operation of the ancillary services (reserve) market, which began in early 2024. In addition, the WESM provides for the introduction of financial transmission rights (FTR). These financial instruments allow participants to hedge price risks associated with differences in locational marginal prices (LMP), mitigating volatility and uncertainty in the market. The implementation of FTRs will follow the transition to full retail competition (IEMOP, 2024).

***Reserve market***

The reserve market is a market-based mechanism for addressing grid imbalances arising from unexpected changes in supply or demand, in which both generation units and registered customers can offer ancillary services. The main product traded is frequency control, which generators can offer in the form of energy reserves and consumers in the form of interruptible loads. Reserve offers are co-optimised with energy offers in the WESM to determine the optimal schedule, resulting in competitive electricity prices for both products (IEMOP, 2024).

As system operator (SO), the National Grid Corporation of the Philippines (NGCP) serves as the single buyer of the ancillary services to operate the system. The SO deals with three types of reserves: regulation, contingency and dispatchable reserves – each of which plays a distinct role in maintaining grid stability. Reserve requirements are dynamically determined on the basis of real-time conditions rather than fixed amounts. In addition to the reserves traded in the market, grid codes cover the other ancillary services necessary for grid stability.

Even though the WESM was designed to co-optimise energy and reserves from its inception, the reserve market only officially began commercial operation in January 2024 after more than two years of planning. Shortly after, in March 2024, the Energy Regulatory Commission (ERC) temporarily suspended the commercial operation of the reserve market following significant price increases in reserve costs. While the reserve market resumed operations later in the year, the pricing methodology has been subject to revisions to ensure system flexibility is procured in a least-cost manner.  (ERC, 2024).

Before operations of the reserve market began, the SO secured reserve requirements bilaterally through contracts with ancillary service providers, involving both firm and non-firm agreements. With the advent of full commercial operation of the reserve market, the SO began procuring reserves from the spot market with financially binding commitments to meet the reserve requirements of the system (DOE, 2024).

***WESM design and its implications for VRE integration***

The WESM's design includes several elements that are set to support the integration of greater shares of variable renewable energy technologies.

- **Integration of VRE forecasting in market clearing:** The WESM incorporates VRE forecasts early on in market clearing projections, from week- to hour-ahead projections. This allows the system and the market to effectively anticipate and integrate VRE generation, taking advantage of up-to-date information to reduce the uncertainty of renewable production.
- **Real-time balancing capability:** With gate closure at close to real time (nine minutes), the WESM allows for frequent updating of renewable production forecasts shortly before delivery. This feature addresses the uncertainty challenges of VREs by allowing them to reflect adjusted forecasts in their market position, thereby pre-empting potential imbalances in real time and reducing reserve costs.
- **Shortened dispatch intervals:** Shortened dispatch intervals from one hour to five minutes allow intra-hour deviations to be reflected in dispatch schedules, enhancing the responsiveness of the system. The increased temporal resolution for market clearing delivers price signals that encourage market participants to adjust their operations in line with VRE output.
- **Consideration of transmission constraints reduces re-dispatch costs:** Locational marginal prices (LMPs) provide geographical signals reflecting network congestion. As the penetration of electricity from renewable sources increases, these signals will indicate where to install new renewable plants and where to reinforce the grid.
- **Reserve market and dynamic reserves:** The reserve market can unlock the flexibility of existing assets and incentivise the emergence of new flexible resources such as battery storage and demand response. Having dynamic reserves further enhances the system's ability to cope flexibly with increasing variability and uncertainty as VRE penetration in the grid increases.
- **Advanced bidding formats:** The market-based dispatch model works with advanced bidding formats (such as ramp rates, storage unit or negative price bids) for which it relies on detailed techno-economic information. This design allows for optimal utilisation of system resources. By enabling market participants to adapt to system conditions in different circumstances, the bidding formats facilitate the integration of renewables.
- **Active participation of demand:** The prospect of demand-side bidding, including for ancillary services, promises to unlock additional flexibility resources beneficial to VRE integration.

Two design elements of the WESM may require reform in the long run as the power system moves towards high shares of variable renewables.

- **Limitations of priority dispatch for conventional RE:** Dispatchable RE sources – e.g. geothermal, biomass and hydro with reservoir – do not have to submit price bids. This inhibits their ability to adjust their output and therefore their flexibility and resource availability in response to real-time conditions and future energy use. This limitation limits their contribution to system stability in the face of fossil phase-down and integration of higher shares of VRE penetration.
- **Price intervention mechanisms** in the form of secondary price caps and emergency market suspensions to address extreme price spikes or sustained high prices in the market may disincentivise investments in flexible resources.

***Distorted market signals: the interplay between baseload bilateral contracts and the WESM***

The bilateral contracts market and the WESM serve different purposes: long-term revenue and supply certainty and risk management – essential for investment decisions – versus dispatch optimisation for efficient and reliable use of resources in the short term. In principle, these long- and short-term markets are complementary and synergistic: the WESM serves as a residual market where power generators sell excess energy not covered by baseload bilateral contracts and suppliers buy additional energy on top of their power supply agreements (PSAs). In practice, distortions arise from the obligations for market participants, which may at times be conflicting. These stem from a mixed market design that combines a central dispatch model with a physical bilateral contract market.

Participation in WESM is mandatory and the rules that govern such participation stipulate that generators must offer all available capacity for market clearing. As such, bilateral contracts define not only the commercial terms for the purchase and sale of electricity but also the power plant's delivery obligations, while actual delivery of the contracted electricity must be scheduled through the spot market. This leaves baseload power plants with an incentive to bid below their marginal costs in order to be scheduled for dispatch and meet the commercial obligations of their PSA upon which remuneration depends. Biased bidding has undermined the strength of the WESM's price signal and its efficiency in clearing the market.

- **Baseload generation units with PSAs that bid below their marginal costs to guarantee dispatch lead to suboptimal scheduling and dispatch of resources.** This results in market outcomes being determined by contractual commitments outside the centralised wholesale market, thereby undermining the WESM's dispatch efficiency, which should be based on techno-economic considerations. For example, coal plants with guaranteed returns from their PSAs may submit offers at low or even negative prices to secure dispatch, resulting in their being prioritised over cheaper and more efficient generation units without a PSA. As market signals are distorted, clearing prices may no longer accurately reflect supply and demand fundamentals.
- **The market distortions limit the WESM's potential to integrate VREs at least cost.** The potential advantages offered by a sophisticated WESM, including enhanced system flexibility through features such as higher temporal and geographical resolution, are undermined by strategic bidding from baseload generators attempting to fulfil physical bilateral contracts. Instead, bilateral commitments override the price signal of the WESM. Priority dispatch rules for renewables have sought to mitigate the resulting dispatch distortions but do not correct the WESM's price signal.

***Impact of DUs' over-contracting strategies***

Over-contracting by distribution utilities compounds existing market inefficiencies. Most DUs choose to over-contract through bilateral contracts – based on peak demand requirements – as a hedge against price volatility and uncertainty on the spot market. Since the volume of energy contracted is fixed over long time periods and based on capacity, whereas actual energy consumption changes hourly, the DUs end up with over-contracted energy during off-peak hours. This leaves them exposed to short-term market dynamics during peak demand periods (ICSC, 2024; forthcoming).

The WESM is then utilised as a secondary market in which DUs can manage their contractual positions. During peak hours, when demand exceeds contracted supply, DUs purchase additional electricity from the spot market at substantially higher prices that are set by inefficient plants not or only partially covered by bilateral contracts. Conversely, during (off-peak) hours with excess energy due to over-contracting, DUs sell the surplus to the WESM at a loss. The resulting inefficiencies and losses that DUs incur are ultimately passed on to consumers in the form of higher tariffs.

**RECOMMENDATION – align bilateral contracts and the WESM to increase dispatch efficiency.**

- **Increase the temporal resolution (e.g. to hourly) in bilateral contracts to better align with price dynamics in the WESM.** Defining offtake at different load levels, such as off-peak and peak hours, would provide greater flexibility and responsiveness to changing market dynamics. However, more profound adjustments will be needed to address the underlying causes of misalignment between bilateral contracts and the WESM (below).

A mixed market design combining a central dispatch model with a physical bilateral contract market is not the way to achieve market efficiency. Conflicting incentives emerge when generators must honour bilateral contractual commitments but rely on a centralised dispatch market rather than self-scheduling to do so. Market or contractual reforms are needed to align incentives between the two trading mechanisms.

- **Central dispatch route: Transform power supply agreements into financial contracts.** Changing PSAs into financial contracts would allow market players to maintain hedged positions and ensure that all physical energy trade goes through WESM, mitigating incentives for biased bidding and ensuring least-cost dispatch. These could take the form of contracts for difference (below).
- **Self-dispatch route: Alternatively, the WESM could be converted into a voluntary net pool market for residual energy trade.** Under this reform option, market participants would use the spot market flexibly for surplus and shortage trades rather than for offering all of their capacity. This would allow them to optimise their contractual position ahead of real-time delivery and meet their bilateral commitments.

***Forthcoming complementary electricity markets***

In addition to bilateral contracts and the WESM, complementary electricity markets are being explored to attract investors and ensure sufficient capacity to meet growing demand. One such market is a forward market for contracts, which would offer an alternative platform for trading short- to medium-term contracts. The market operator is considering various alternative features for the forward market. These include auction-based trading of standardised forward (monthly) contracts, exchange-traded contracts with a bilateral settlement and, further in the future, exchange-traded contracts with centralised settlement.

Contracts for difference (CfDs) are also under consideration. CfDs allow market participants to hedge against price differentials by agreeing on a strike price and paying or receiving the difference between it and the actual spot market price at the time of consumption. CfDs would direct energy trade through the WESM, addressing the mismatch between existing bilateral contracts and the spot market. Opportunities for changing baseload power supply agreements into contracts for difference would need to be explored to improve the value of short-run price signals and dispatch efficiency.

The Philippines does not have capacity markets, but the government is considering introducing one for long-term system adequacy. Existing power supply agreements do include capacity-based remuneration. A capacity market could play a role in procuring flexible capacity and storage solutions. Retail market: retail competition and open access (RCOA)

### Retail competition and open access (RCOA)

RCOA is a policy framework defined under the Electric Power Industry Reform Act (EPIRA) that establishes competition in the retail electricity market by allowing qualified end users, referred to as contestable consumers, to voluntarily choose their retail electricity supplier (RES). Eligible consumers are defined on the basis of thresholds established by the ERC according to average monthly peak demand. The RCOA encompasses the competitive retail electricity market (CREM) and additional programmes such as the Electricity Retail Aggregation Program (ERAP) and the Green Energy Option Program (GEOP) (PEMC, 2024d).

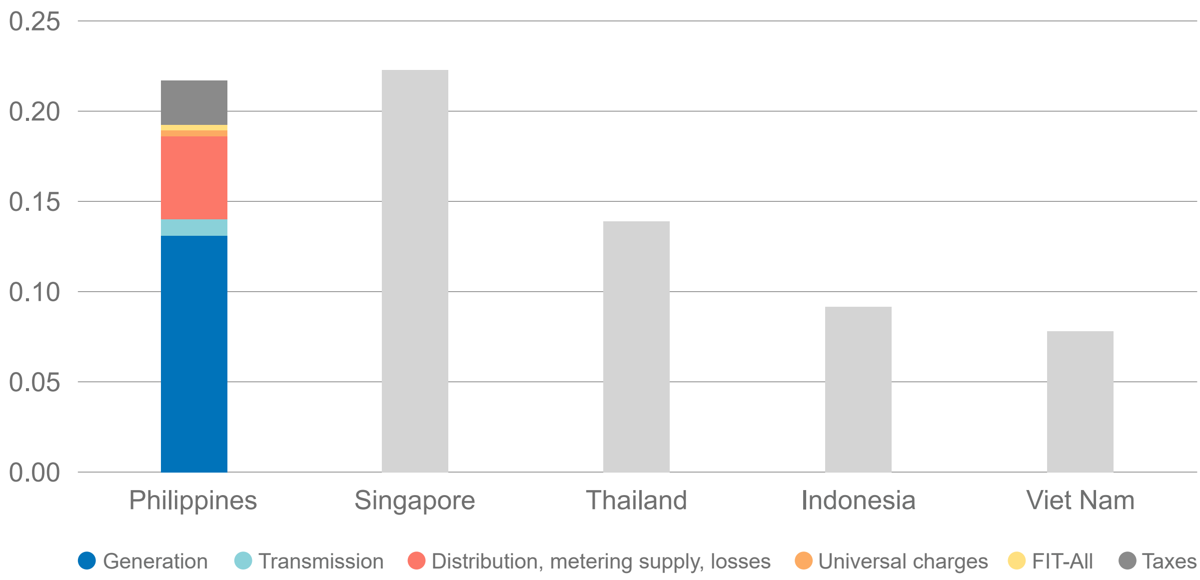
- **In the CREM, RESs compete to offer electricity to contestable consumers.** The CREM began commercial operation in Luzon and Visayas in 2013, and recently expanded its scope to Mindanao in 2023, a development contingent upon the operation of WESM in the region (DC2023, draft).
- **The GEOP offers end users the possibility to choose renewable energy resources as a source for their electricity consumption.** With a minimum threshold of at least 100 kW, the GEOP further lowers the threshold to encourage retail participation. More details on the GEOP and other market-related renewable energy support mechanisms in the country are discussed in the "Policy instruments for VREs" section.
- **The ERAP allows aggregation to participate in the CREM.** Introduced in 2022, it allows two or more end users within a contiguous area to pool their demand and collectively reach the required threshold – 500 kW for the RCOA, 100 kW for the GEOP – and thus be treated as a single contestable customer, enabling them to participate in the CREM. The ERAP created a new entity called retail aggregators to allow the aggregation of end users and their participation in the market.

### Electricity tariff design

Two decades after the EPIRA came into force, electricity rates in the Philippines remain among the highest in the region (Figure 16; Global Petrol Price, 2024; Ravago, 2023). Although recent increases in electricity prices can be attributed to demand growth and rising fuel prices, the notable discrepancy between electricity tariffs in the Philippines and those in other countries in the region stems primarily from subsidy reform, an overreliance on imported coal and to a lesser extent gas, and generous PSAs that transfer market risk to consumers.

Electricity rates are regulated according to "the principle of full recovery of prudent and reasonable economic costs incurred" by the generation company and the distribution utility and are broken down into charges for generation, transmission and distribution, as well as other components (DOE, 2022). Electricity rates vary according to the type of customer and supplier (e.g. DU or RES) and market (captive or contestable), yet all of them are subject to the charges below.

**Figure 16. › Average residential electricity rates in selected countries (June 2023)**




Note: The Philippines' tariff breakdown based on reported charges from utilities

- **The generation charge constitutes the largest portion of the electricity rate (~50-60 percent).** This charge is a direct pass-through to allow distribution utilities to recover all their costs associated with the purchase of electricity through power supply agreements and transactions on the WESM. As such, fuel costs in electricity generation are directly reflected in this charge as they are the main cause of increases and fluctuations in the price of electricity. The cost of generation varies for each DU depending on its power procurement strategy. It is worth noting that the generation charge in the electricity tariff is lower on average for contestable consumers than for captive consumers (it was 39 percent lower in 2022), which highlights the benefits of competitive dynamics within the segment (PEMC, 2024e).
- **Regulated by the ERC, the transmission charge (~five percent of the tariff) covers the costs of the transmission network and payments are directed to the TSO (the National Grid Corporation of the Philippines, NGCP).** The transmission charge also reflects the costs of ancillary services incurred by the NGCP. Reserve market costs (and costs from ancillary service procurement agreements, ASPAs) are passed onto end users via the transmission charge.
- **The distribution, metering, supply and system losses charges constitute about 20 percent of the tariff.** These charges are intended to recover the costs of developing and maintaining the distribution system, maintaining metering facilities, service-related functions such as billing and costs related to electricity losses, respectively.
- **Universal charges (UC) cover legacy debts and initiatives to support the electrification of remote off-grid areas and environmental programmes (two percent of the tariff).** The legacy charges of the UC are intended to address historical financial obligations from IPP contracts and debts accumulated by the National Power Corporation (NPC) during the electricity crisis of the 1990s.
- **The Feed-in Tariff Allowance (FIT-All) is a component of the electricity tariff designed to raise the necessary funds for RE support mechanisms (< one percent),** specifically the feed-in tariff (FIT) and the Green Energy Auction Program (GEAP). The FIT-All ensures that the costs associated with these programmes are collected from electricity consumers and

placed in the FIT-All fund managed by TransCo which, in turn, pays the accredited RE developers. The support mechanisms for RE, including FIT and the GEAP, are detailed in the "Policy instruments for VREs" section. Finally, the electricity rate also includes VAT and other taxes (12 percent).

The design of the electricity tariff underscores the critical role of the fuel mix in determining energy affordability. With fuel costs comprising the largest portion of the tariff, the country's reliance on imported fuels exposes it to global price fluctuations, as demonstrated during the recent global energy crisis and the pandemic (Lui et al., 2022).

**Transitioning to indigenous RE resources offers a pathway to reduce end consumers' exposure to high and volatile electricity prices.** However, adjustments are required to ensure that cost reductions from low-cost renewable electricity are reflected in final tariffs. Although the impact is negligible at the current shares of VREs, capacity payments to baseload assets, which are inversely linked to the capacity factors specified in PSAs, may forego some of the cost savings at higher VRE shares until electricity demand growth catches up. This further underlines the need for contractual reform.

**The design flaws of the PSAs are transferred to the generation tariffs paid by end consumers.** Current PSAs burden consumers with high costs and excessive risk, as well as preventing the WESM's cost efficiency and flexibility signals from reaching consumers.

Although regulatory provisions allow for time-of-use tariffs to optimise demand management, consumers currently have little exposure to dynamic pricing. This diminishes incentives for demand response and leaves unexplored potential system flexibility that could support the integration of VREs. Initiatives such as Meralco's Peak/Off-Peak (POP) programme demonstrate the potential of alternative pricing schemes to promote cost savings and enhance demand-side flexibility (Meralco, 2024a).

## Recommendations

### Pillar 1 › Provide long-term investment certainty for variable renewable energies (VREs)

Renewable energy targets and a variety of policy incentives have provided investors with the revenue certainty needed for long-term investment decisions. RE auctions are the main instrument in the Philippines to guarantee revenue certainty and reduce market risks, thereby de-risking investments and lowering financial costs. Complementary measures can be implemented to reduce the financial risks associated with RE projects.

- **Continuation of the RE auction programme:** The Green Energy Auction Program (GEAP) offers a stable and predictable framework for investors and project developers. Looking ahead, the scope of the auctions could be widened to encompass all RE sources and the price ceiling could be eliminated to encourage more participation in the auctions and improve transparency with respect to the way the capacity targets are determined for each technology, thereby building greater trust in the process and leading to more subscribed auctions.
- **Ensure the Renewable Portfolio Standard (RPS) programme's revenue predictability:** Linking renewable energy credits (RECs) to RE power supply agreements (PSAs) auctioned in the GEAP (with the opt-in mechanism) could stabilise REC prices, providing a stable revenue stream for producers.

► **Promote distributed solar deployment:** The Philippines has achieved successes in deploying VREs through its centralised auction procurement programme, yet the potential for greater decentral deployment remains largely untapped. The Green Energy Option Program (GEOP) should be scaled and permitting constraints eased. Meanwhile, behind-the-meter deployment could be further supported by fiscal reforms and new financial models, two aspects covered in more detail in Ahmed (2018).

### Pillar 2 › Enhance system flexibility to integrate VREs into the system at the least cost

Physical long-term contracts were designed for a baseload-oriented power system and impose significant rigidity on dispatch decisions and financial transactions. They undermine the WESM's potential to fully exploit system flexibility.

► **Remove incentives for baseload generation:** The overcapacity of baseload generation increases electricity costs and the system's rigidity. This should be tackled by making market design adjustments that better reflect the cost of coal power. For a start, sliding capacity payments to baseload assets (inversely related to plant load factors) should be abolished in order to reintroduce a manageable level of dispatch risk for producers, thereby reducing the system costs of VRE integration and benefitting consumers with lower tariffs. Corresponding carve-out clauses could be introduced into standard PSAs to exempt distribution utilities from the financial risk of underutilised coal plants.

► **Mitigate the mismatch between bilateral contracts and the WESM to increase the information value of short-run price signals**

1: The market exchange route (central dispatch): Forward financial contracts such as contracts for difference (CfDs) could replace bilateral physical contracts altogether. Transforming PSAs into financial contracts would allow market players to maintain hedged positions and ensure all physical trade of energy goes through the WESM, mitigating incentives for biased bidding and ensuring efficient dispatch. If such contracts are designed properly, generators will be compelled to base their bidding strategy on real-time signals rather than on physical bilateral contracts.

2: The bilateral route (self-dispatch): Alternatively, the WESM could be reformed to create a residual market for surplus and shortage trade, i.e. a voluntary net pool market, helping market participants to balance their position ahead of real-time delivery. This would require, amongst other things, a change in market rules to give producers the flexibility to decide how much capacity they want to offer on the spot market.

► **Exploit flexibility potential in the system:** Encourage the active participation of flexible resources and use of supply-demand management techniques: empower aggregators, introduce dynamic tariffs and appropriately value ancillary services.

### Pillar 3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs

Despite high reserve margins, the system faces stress during peak demand months, which is reflected in elevated spot prices. To address these issues and bolster resource adequacy, several measures could be considered.

- **Reduce dependency on imported coal:** An overreliance on baseload coal has increased the costs of meeting peak demand. Capacity expansion of indigenous RE reduces dependency on imported coal, enhancing adequacy and energy security, and opens up opportunities to meet peak demand affordably.
- **Reform the market design to deliver incentives compatible with a dynamic system:** Market design and policy instruments should evolve to shape the power system around dynamic system-level resourcing rather than around baseload generation capacity expansion. Moving towards this, assessments of system flexibility needs could be introduced to inform system planning and ensure cost-efficient investment choices.
- **Incorporate flexibility requirements into capacity expansion incentives.** Flexibility resources could be procured through auctions and awarded long-term contracts that provide revenue certainty as well as revenue from the spot market. The capacity mechanism currently under consideration should include flexible and renewable energy technologies. By aligning the design of these mechanisms with the future requirements of a transitioning energy landscape, the power system will be better equipped to integrate growing VRE shares.

### Pillar 4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets

Keeping inefficient fossil fuel power plants in the system hinders system flexibility, cost-optimised resource adequacy and affordability. The following measures could be considered to efficiently retire carbon-intensive power plants.

- **Keep the moratorium on new coal power plants in place:** The decision to halt the addition of new coal power plants is a clear signal that cleaner, more flexible and cheaper alternatives should be prioritised over fossil fuel baseload plants. Given that it is currently a temporary measure, making this decision a permanent policy would create certainty about the Philippines' ambition to transition away from coal in favour of renewables.
- **Remove inefficient incentives to baseload plants:** Eliminate design elements in power supply agreements intended to safeguard baseload operation, such as sliding capacity payments and minimum-take obligations. These delay the phasing out of fossil fuel plants in the system at the expense of power system efficiency.

### Pillar 5 › Ensure affordable electricity for consumers while maintaining the sector's financial sustainability

Electricity prices in the Philippines are higher than those of its peers. Energy affordability is at the core of a successful energy transition.

- **Equitable risk sharing and removal of the excessive cost burden for end users:** Currently, consumers bear a disproportionate burden of the risks that are passed on from PSAs and reflected in final electricity tariffs. To address this, PSA designs should be revisited to protect end users from the financial impacts of underutilised fossil fuel plants and provide safeguards against fuel price shocks. In an energy transition context, reintroducing a manageable level of market risk from ratepayers to investors and producers is key when it comes to directing investment towards renewables and flexible resources while ensuring energy affordability.
- **Encourage efficient contracting from suppliers:** Adjust regulations and incentives to ensure that utilities shoulder a degree of demand risk instead of shifting it entirely to ratepayers. This would encourage more efficient risk management and capacity procurement, ultimately reducing rates for end consumers.
- **Translate the availability of cheap renewables in the system into lower electricity tariffs:** The Philippines should address the challenges in its auction design to rapidly increase variable renewable energy capacity. By increasing the auction volumes for renewables and utilising the opt-in mechanism, greater shares of VREs in the supply mix will reduce the generation component of the electricity tariff.
- **Increase the contestable consumer base:** Promote wider participation in the GEOP, empower aggregators and lower the retail competition and open access (RCOA) threshold for participation in the retail market, allowing more consumers – especially households and small businesses – to gain access to lower and more efficient tariffs.

# Annex A: Why market design matters

Electricity markets differ in scope, operational mechanisms and the outcomes they ought to deliver. At a fundamental level, markets are platforms for the exchange of services and goods that involve buyers, sellers and traders. Electricity market structures vary according to their number of participants, degree of market concentration, ease of entry and exit, differentiation of products and price formation, amongst other things. Their form is closely tied to the degree of vertical and horizontal integration across the value chain, the ownership structures in place and the institutional framework governing the sector. Much like other sectors, electricity markets can resemble monopsonies, oligopolies, oligopsonies, monopolistic competition or perfect competition. Following the advent of market liberalisation in the 1980s and 1990s, electricity markets became associated with new models that aimed to approximate perfect competition in the form of restructured and competitive wholesale energy markets. This model was not uniformly adopted by all countries, many opting instead for variations or alternatives that retained features of vertically integrated systems. As a result, today's electricity markets take many forms and span a broad range of regulatory configurations of power systems around the world.

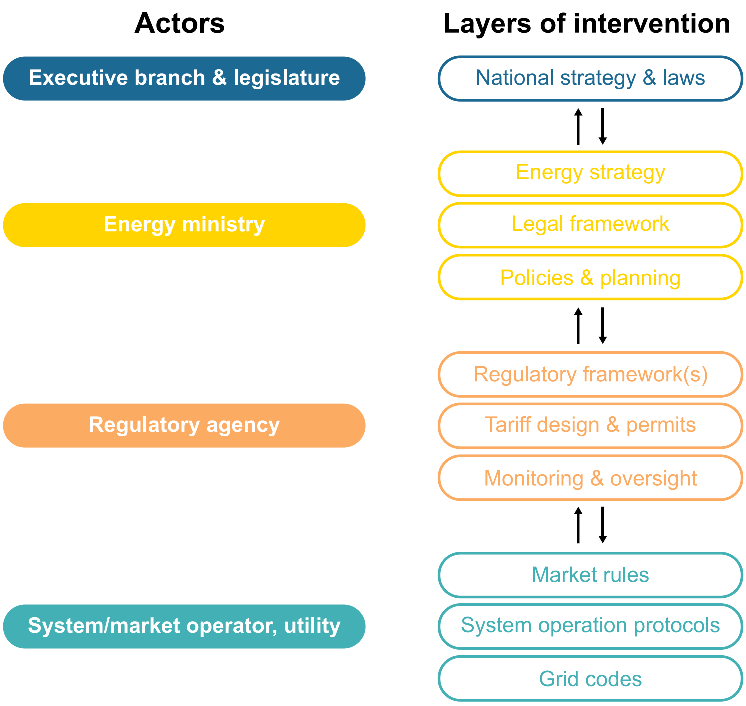
This report employs a broad definition of electricity market design to denote the parameters governing electricity supply, demand and investment that allow for the contractual exchange of electricity and related products between parties. This umbrella term encompasses the multiple differentiated markets (investment, financial, capacity, energy, ancillary services) along the supply chain – where applicable – and includes regulated markets involving fewer buyers and sellers and limited price discovery.

More than in any other sector, states set the boundaries within which electricity sectors are allowed to operate "freely" and determine where or when central authorities should assert control to achieve broader policy and strategic objectives. By nature, electricity market design reflects a balance struck between the role of the state and markets in delivering good sector outcomes. This balance differs from one country to another and is subject to technology requirements, economic considerations and political interests; it is also a defining aspect of how the sector is organised.

Electricity as a product is unique in its combination of high upfront capital costs, inelastic demand in the absence of close substitutes and tight interdependencies as a network energy with a continuous system balancing requirement yet limited storage options. Electricity markets must reflect the physical requirements of the power system to ensure the efficient dispatch of supply and balancing of load while at the same time providing adequate incentives for investment. Electricity market design is about getting the mechanisms and incentives right in order to 1) ensure efficient operation of the system and 2) get the sector where it needs to be as laid out in policy roadmaps and long-term strategies. This is a pressing matter given that decarbonisation is being added as a core objective of what electricity sectors should deliver; in the process, it is transforming traditional notions of security of supply, system reliability and the way in which the demand-side interacts with the system.

Electricity market design comprises the institutional arrangements, policies, regulations, market rules, codes and operational practices that jointly define the parameters for the electricity market and the opportunities and incentives it provides to participants. Actors across the tiers of government and the electricity sector are involved in market design and regulation, a stylised overview of which is presented in Figure 17. Electricity market design: Layers of operation and regulationTwo points are worth highlighting. First, governance and electricity market structures are linked. For example, electricity sectors in which the state has retained ownership of a large share of generation assets are often headed by an influential energy ministry that assumes some of the responsibilities that are delegated elsewhere to independent regulators. Restructured markets have seen a trend in the opposite direction, with greater specialisation of and differentiation between regulatory functions and bodies. Second, a range of secondary actors (such as associations, producers, universities and research institutes) may shape the evolving design of the electricity market through consultations and feedback loops. Many countries have formalised this process by incorporating it into the policy cycle. In some countries, the feedback mechanisms are less formalised in nature.

**Figure 17. › Electricity market design: Layers of operation and regulation**




## Market design for renewables-based transitions

The primary objectives of electricity market design are threefold: ensure short-term reliability, safeguard long-term resource adequacy and promote least-cost system operation. The race to curb global emissions introduced decarbonisation as an additional target for the electricity sector. This has profound implications for the transformation of power systems and requires a novel set of accompanying market and policy arrangements.

In the prevailing technology landscape, power sector decarbonisation requires the vast deployment of variable renewables. VREs entail new requirements for investment and system integration due to six core features[14]:

**I. Variable (non-dispatchable) supply:** VRE output is contingent on weather conditions such as wind speed and solar radiation

**II. Uncertain supply:** Accurate meteorological forecasts are limited to windows close to delivery

**III. Location constrained:** Resource availability is not evenly distributed geographically and could be far away from load centres. This affects utility-scale VREs and to a much lesser extent distributed energy resources.

14 A detailed overview of the system implications of VRE properties can be found in IEA (2014).

**IV. Differentiated cost structure:** VREs have high upfront capital costs and close to zero short-run marginal costs
**V. Non-synchronicity:** VREs are connected to the grid via electronic power converters instead of being electro-mechanically coupled through a rotating mass
**VI. Modularity:** VREs have smaller units than their conventional counterparts and can be deployed across a wide range of sizes (<0.1 MW >1 GW)

**I)** VREs introduce a greater degree of supply variability into the power system. The magnitude of system-level variability is context specific and depends by and large on three interrelated factors: 1) the size of the electricity network and opportunities for balancing supply and demand across wider geographic zones; 2) the VRE mix and extent to which the intermittency of individual units is offset at the aggregate level (e.g. negative output correlation between solar and wind power in some regions); 3) the coincidence of VRE output and load (demand) in spatial and temporal terms. As a rule, power system flexibility – along sequential time intervals ranging from minutes to years – is a requirement for the integration of VREs. The magnitude of flexibility provisions typically increases with VRE penetration rates and relates to supply, demand and network adjustments.

**II)** Where variability results in anticipated changes to supply patterns, uncertainty gives rise to unforeseen deviations from the forecast supply and demand balance. The accuracy and lead time of meteorological forecasts introduce a layer of uncertainty into daily power generation predictions. This may in turn call for higher reserve requirements (IEA, 2014). Wind and solar energy forecasting has improved greatly over the years and continues to evolve, reducing the need for additional backup supply caused by uncertainty (Sweeney et al., 2019). The adoption of advanced forecasting models remains a priority for many countries in the earlier stages of renewable energy deployment.

**III)** Location constraints may necessitate additional transmission infrastructure investment to connect remote production zones with load centres and avoid grid congestion. A lack of grid expansion and spatial differentiation between non-dispatchable renewables are likely to increase the use of costly system interventions such as redispatch or curtailment in order to maintain system operability. The resulting inefficiencies may prompt regulators to redefine bidding zones or consider introducing nodal pricing where this is not already in use so as to ensure that market outcomes reflect the underlying physical infrastructure. Germany's power system exemplifies this situation (Sweeney et al., 2019).

**IV)** High upfront capital costs mean that financing is a crucial factor in the overall project costs of new renewable capacity additions. Higher risks and weaker capital markets tend to drive up borrowing costs in emerging economies, elevating the need for de-risked financing opportunities (Nelson & Shrimale, 2014). To this end, variable renewables are typically deployed via long-term energy contracts or purchase power agreements with terms that secure revenue, mitigate a project's risk profile and lower capital costs. VREs' low short-run costs render them the most competitive generation source on a marginal cost basis. Being dispatched first, VREs affect the capacity factors of conventional baseload assets. In restructured market environments this may then depress wholesale electricity prices. Where they are in use, short-term electricity markets have not delivered investment certainty for variable renewables. However, they do optimise dispatch efficiency, allowing participants to adjust their contractual positions close to the point of delivery to match the fluctuating output profile of variable renewables.

**V)** Synchronous generators such as coal power, gas power, hydropower, geothermal power, biomass and concentrated solar power plants help maintain frequency control through inertia and spinning reserves. Wind turbines have limited (mechanical) inertia but, given their electronic inverter-based grid connection, do not deliver a mechanical inertial response to fluctuations in system frequency (Eriksson et al., 2017). Solar PV has no mechanical rotation and, therefore, is inertia-free. VREs and battery storage technologies can deliver synthetic (electronic) inertia through smart inverters that automatically adjust output to restore system frequency to the standard levels (Tielens & Hertem, 2016). Studies have highlighted how inverter-based resources can detect and respond to frequency deviations more quickly than conventional sources (Denholm et al., 2020). Furthermore, new technology applications, such as grid-forming inverters, show potential for maintaining reliability in inverter-based systems without synchronous generators (Rathnayake et al., 2021; Unruh et al., 2020).

**VI)** The small unit sizes of VREs, particularly of solar PV, create opportunities for electricity generation at the distribution level. One implication is that the distribution system can no longer be considered a passive load. Bi-directional power flows become imperative and, at high deployment rates, reverse flows from distribution to transmission level may start to occur, which may trigger a need for grid upgrades. In certain cases, distributed generation may overtake peak demand, thereby becoming the main determinant of infrastructure size and the corresponding network investment requirements (IEA, 2014). The modular nature of VREs is at the core of the broader energy transition trend towards “decentralisation” to which we briefly turn in Box 8.

**Box 8. › Decentralisation, electrification and digitalisation: three interwoven trends in transitioning power systems**

The policy push towards decarbonisation and the accompanying shift from fossil to renewable primary energy sources has engendered two additional power sector transition trends: decentralisation and electrification, both of which are supported by the exogenous trend of digitalisation.

**Decentralisation** is a direct result of the modular nature of wind and, above all, solar power and battery storage and refers to the increased deployment of energy resources at the distribution level. This creates new participants in the system (prosumers, distributed generators) and requires novel approaches to distribution-level system management, for example through local energy trade and storage solutions. Decentralisation requires grid or software upgrades to facilitate bi-directional power flows and may trigger a need for new tariff designs to maintain network investment in the face of reduced utility revenues. Decentralisation and distributed assets complement but do not replace the need for centralised management and utility-scale assets.

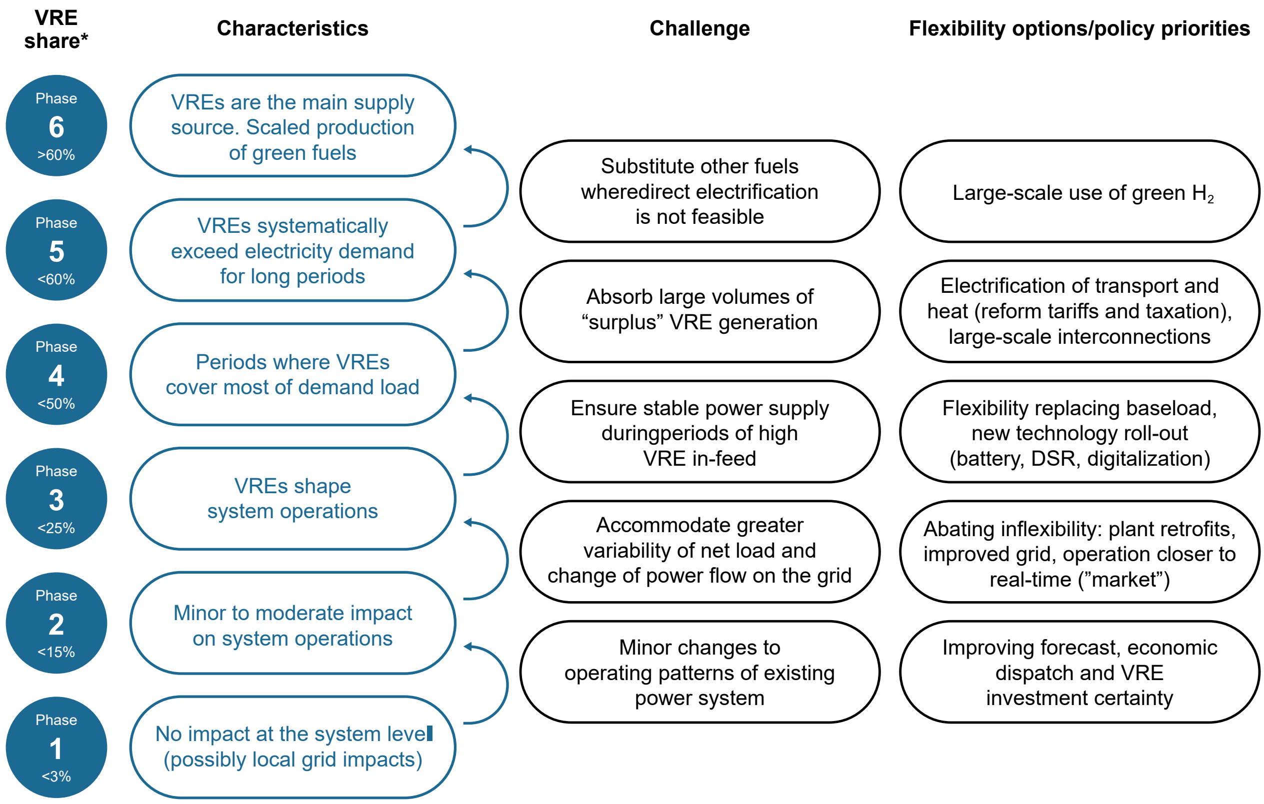
**Electrification** results from the fact that electricity is becoming the core energy vector of clean energy systems. It provides a route for decarbonising demand sectors such as industry and transport through direct electrification and the use of clean fuels produced with renewable electricity. Electrification implies a growing demand for power, in turn necessitating greater investment in supply and networks (incl. charging infrastructure) alongside new forms of demand-side management. Decentralisation and electrification present TSOs and DSOs with a more complex environment in which to maintain system reliability.

**Digitalisation** supports the reliability and operability of increasingly complex power systems by making accurate real-time data available across all operational layers. Digital technologies improve the predictive maintenance of assets, short-term generation forecasts and local/central grid control and monitoring, and help better coordinate supply and demand decisions – for example through virtual power plants and smart grids. Besides improving coordinated system management, digitalisation supports demand-side integration and may unlock new flexibility sources, including from small-scale assets. Overall, enhanced digitalisation of power systems allows for more efficient use of the electricity network and reduces the cost of integrating variable renewable energy sources.

All three trends present opportunities for integrating variable renewables. Reaping their benefits is contingent on having an electricity market design that delivers the appropriate incentives for consumers, producers and prosumers to align their activities with evolving system needs.

The spatial and temporal features of electricity production and demand become increasingly pertinent to system reliability with greater deployment of variable renewables. The system value of electricity becomes location- and time-bound as flexibility sources must be able to cover surpluses and shortfalls in VRE production at short notice and for varying time periods, and must be located such that they minimise potential grid congestion. While not noticeable at low shares of VREs, such system effects should be anticipated early on to ready systems for a rapid renewable energy technology ramp-up and avoid bottlenecks later.

**Figure 18. › Priorities for system transformation at sequential stages of VRE in-feed**




*Output shares are indicative and depend on power system specificities.

Source: Agora Energiewende, adapted from IEA.

The priorities for transforming power systems evolve as the share of VRE feed-in rises (Figure 18). As of 2023, ASEAN member states were in phases 1 and 2 of VRE integration. The priorities for the region at large are to scale investments in new clean capacity, strengthen networks, abate inflexible arrangements, retrofit conventional assets and move system operations closer to real time. Addressing these priorities calls for an enabling investment environment that ensures at the very least a level playing field across technologies, creates certainty about the business opportunities for clean energy solutions, including flexibility services, and reduces project risk. In parallel, a (dispatch) strategy for integrating variable energy sources into the power system should be at hand to ensure efficient utilisation of the network and generation portfolio, thereby keeping system costs at a minimum.

These two core requirements, low-carbon investment (renewables, flexibility technologies, networks) and cost-effective integration of variable supply sources into the power system, lie at the heart of the market design challenge for ASEAN jurisdictions. Policymakers and regulators thus face a formidable yet surmountable task that will involve revisiting the policy toolbox, market rules and operational practices across the layers of market regulation while considering interactions between them. We break down the requirements for renewables-based transitions into the following five outcome-oriented principles, which underpin the analysis presented in Chapters 3-6:

1 › Provide long-term investment certainty for variable renewable energies (VREs)
2 › Enhance system flexibility to integrate variable renewables into the system at the least cost
3 › Safeguard system adequacy in line with long-term decarbonisation and flexibility needs
4 › Provide clarity on and efficiently manage the retirement of inflexible and carbon-intensive assets
5 › Ensure affordable electricity for consumers while maintaining the sector’s financial sustainability

## List of acronyms

| | |
|---|---|
| ADB | Asian Development Bank |
| AEDP | Alternative Energy Development Plan |
| AGC | Automatic generation control |
| AP | Availability payment |
| ASEAN | Association of Southeast Asian Nations |
| BAPPENAS | Badan Perencanaan Pembangunan Nasional (the Indonesian Ministry of National Development Planning) |
| BCG | Boston Consulting Group |
| BE | Buddhist Era |
| BESS | Battery energy storage system |
| BLT | Build-lease-transfer |
| BNE | Best new entrant |
| BOT | Build-operate-transfer |
| BOOT | Build-own-operate-transfer |
| BPP | Biaya Pokok Penyediaan (the cost of power generation) |
| BST | Bulk supply tariff |
| C&I | Commercial and industrial |
| CAN | Capacity add-on |
| CAPEX | Capital expenditures |
| CEPA | Committee on Energy Policy Administration |
| CfD | Contract for difference |
| COD | Commercial operation date |
| CP | Capacity payment |
| CPV | Communist Party of Viet Nam |
| CREM | Competitive retail electricity market |
| CSP | Competitive selection process |
| DCC | Dynamic currency conversion |
| DCQ | Daily contract quantity |
| DEN | Dinamika Energitama Nusantara (Indonesia's National Energy Council) |
| DER | Debt-to-equity ratio |
| DJK | Daiichi Jitsugyo Co., Ltd. (a trading company specialised in industrial machineries) |
| DMO | Domestic market obligation |
| DOE | Department of Energy (the Philippines) |
| DPD | Indonesian Council of Regional Representatives |
| DPPA | Direct power purchase agreement |
| DPR | Indonesian Council of the People's Representatives |
| DPV | Distributed photovoltaic |
| DSO | Distribution system operator |
| DTO | Domestic tax obligation |
| DUs | Distribution utilities |
| ECs | Electric cooperative |
| EENS | Expected energy not served |
| EGAT | Electricity Generating Authority of Thailand |
| EGCO | Electricity Generating Co., Ltd. |
| EP | Energy payment |
| EPC | Engineering, procurement and construction |

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|---|---|
| EPIRA | Electric Power Industry Reform Act |
| EPPO | Energy Policy and Planning Office (Thailand) |
| EPTC | Electricity power trading company |
| ERAP | Electricity Retail Aggregation Programme |
| ERAV | Electricity Regulatory Authority of Viet Nam |
| ERC | Energy Regulatory Commission |
| ERC Sandbox | Energy Regulatory Commission Sandbox |
| EREA | Electricity and Renewable Energy Authority |
| ESB | Enhanced single buyer (Thailand) |
| ESDM | Kementerian Energi dan Sumber Daya Mineral (the Indonesian Ministry of Energy and Mineral Resources) |
| ETS | Emissions Trading System |
| EVN | Electricity Viet Nam |
| EVNCPC | Central Power Corporation (Viet Nam) |
| EVNHANOI | Hanoi Power Corporation |
| EVNHCMC | Ho Chi Mihn City Power Corporation |
| EVNNPC | Northern Power Corporation (Viet Nam) |
| EVNNPT | National Power Transmission Corporation (Viet Nam) |
| EVNPECC3 | Power Engineering Consulting Joint Stock Company 3 (Viet Nam) |
| EVNSPC | Southern Power Corporation (Viet Nam) |
| EVOSS | Energy Virtual One Stop Shop |
| FDI | Foreign direct investment |
| FiT (or FIT) | Feed-in Tariff |
| FiT-All | Feed-in-Tariff Allowance |
| FiTf | Fixed Feed-in Tariff |
| FiTy | Variable Feed-in Tariff |
| FMP | Full market price |
| Ft | Fuel adjustment charge |
| FTI | Federation of Thai Industries |
| FTRs | Financial transmission rights |
| GDP | Gross domestic product |
| GEAP | Green Energy Auction Program (the Philippines) |
| GENCOs | Power generation corporations |
| GEOP | The Green Energy Option Program (the Philippines) |
| GHG | Greenhouse gas |
| GW | Gigawatt |
| GR | Government regulation |
| HVDC | High-voltage direct current |
| Hz | Hertz (unit of frequency) |
| kV | Kilovolt |
| kVA | Kilo-volt ampere |
| IDR | Indonesian Rupiah (currency) |
| KWh | Kilowatt-hour |
| IEA | International Energy Agency |
| IEMOP | Independent Electricity Market Operator (the Philippines) |
| IESR | Institute for Essential Services Reform |
| IPPs | Independent power producers |
| IRENA | International Renewable Energy Agency |

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|---|---|
| IRR | Internal rate of return |
| ISO | Independent system operator |
| IUPTL | Izin Usaha Penyediaan Tenaga Listrik (mandatory business licence) (Indonesia) |
| IUPTLS | Distribution electricity supply business licence for own interest (Indonesia) |
| IUPTLU | Integrated electricity supply business permit (Indonesia) |
| JETP | Joint Energy Transition Partnership |
| JICA | Japan International Cooperation Agency |
| KEN | (Cross-Sectoral) National Energy Policy (Indonesia) |
| LCOE | Levelised cost of electricity |
| LCRs | Local content requirements |
| LDUs | Local distribution utilities |
| LMP | Locational marginal pricing |
| LNG | Liquefied natural gas |
| LOLE | Loss of load expectation |
| LOLP | Loss of load probability |
| LRES | Local retail electricity supplier |
| MDBs | Multilateral development banks |
| MEA | Metropolitan Electricity Authority (Thailand) |
| MEMR | Indonesian Ministry of Energy and Mineral Resources |
| MKRI | Mahkamah Konstitusi Republik Indonesia (Constitutional Court of the Republic of Indonesia |
| MO | Market operator |
| MOE | Ministry of Energy (Thailand) |
| MOF | Ministry of Finance (Indonesia, Viet Nam) |
| MOIT | Ministry of Industry and Trade (Viet Nam) |
| MSOE | Ministry of State-owned Enterprises (Indonesia) |
| MtCO2 | Million tonnes of carbon dioxide |
| MTJDA | Malysia-Thailand Joint Development Area |
| MVA | Megavolt-ampere |
| MVIP | Mindanao-Visaya Interconnection Project |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NCC | National Control Centre (Thailand) |
| NDCs | Nationally determined contributions |
| NEM | Australian National Electricity Market |
| NEMP | National Energy Master Plan (Viet Nam) |
| NEPC | National Energy Policy Council (Thailand) |
| NEPO | National Energy Policy Office (Thailand) |
| NGCP | National Grid Corporation of the Philippines |
| NLDC | National Load Dispatch Centre (Viet Nam) |
| NOLCL | Net operating loss carry-over |
| NPC | National Power Corporation (the Philippines) |
| NREB | National Renewable Energy Board (DOE – the Philippines) |
| O&M | Operation and maintenance |
| OECD | Organisation for Economic Co-operation and Development |
| OPEX | Operating expenses (or expenditure) |
| PCC | Philippines Competition Commission |
| PCs | Power corporations |

| | |
|---|---|
| PDF | Power Development Fund |
| PDP | Power Development Plan (Thailand, Viet Nam) |
| PDP8 | Power Development Plan VIII (Viet Nam) |
| PEA | The Provincial Electricity Authority (Thailand) |
| PEMC | Philippines Electricity Market Corporation |
| PERPRES | Peraturan Presiden (a presidential regulation, PR) |
| PhP/kWh | Philippine peso per kilowatt-hour |
| PLN | Perusahaan Listrik Negara (Indonesian stated-owned utility) |
| POP | Peak/off-peak |
| PPAs | Power purchase agreements |
| PPU | Private power utility |
| PPPs | Public-private partnerships |
| PSAs | Power supply agreements |
| PSH | Pump storage hydropower |
| PSALM | Power Sector Assets & Liabilities Management Corporation |
| PSPP | Power Supply Procurement Plan (the Philippines) |
| PT PLN EPI | Perusahaan Listrik Negara Energi Primer Indonesia (sub-holding of PT PLN which operates in the primary energy sector) |
| PT PLN ICON | PT PLN Comnets Plus (telecommunications and information technology company) |
| PLUS | Perusahaan Listrik Negara Nusantara Power (sub-holding of PT PLN engaged in |
| PT PLN IP | electricity generation and other supporting businesses) |
| PT PLN NP | Perusahaan Listrik Negara Indonesia Power (power-generating subsidiary of state-owned electricity firm PT PLN) |
| PTT | Petroleum Authority of Thailand |
| PV | Photovoltaic |
| PVN | Petro Viet Nam |
| PwC | PricewaterhouseCoopers International Limited |
| R&D | Research and development |
| Ratchaburi | Ratchaburi Electricity Generating Holding Co., Ltd. |
| RCOA | Retail competition open access |
| RE | Renewable energy |
| RECs | Renewable energy certificates |
| REDS | Renewable Energy Development Strategy (Viet Nam) |
| REM | Renewable energy market |
| REMB | Renewable Energy Management Bureau (the Philippines) |
| RES | Renewable energy storage |
| ROIC | Return on invested capital |
| RPS | Renewable portfolio standard |
| RoR | Rate of return |
| RTD | Real-time dispatch |
| RTP | Real-time pricing |
| RUKD | Rencana Umum Ketenagalistrikan Daerah (Indonesia’s Regional Electricity General Plan) |
| RUKN | Rencana Umum Ketenagalistrikan Nasional (Indonesia’s Blueprint for National Electricity Planning) |
| RUPTL | Rencana Usaha Penyediaan Tenaga Listrik (Indonesia’s Electricity Supply Business Plan) |
| SBM | Single-buyer model |

| | |
|---|---|
| SCED | Security-constrained economic dispatch |
| SET | Stock Exchange of Thailand |
| SIS | System impact study |
| SMHPs | Strategic and multipurpose hydropower plants |
| SMO | System and market operator |
| SMP | System marginal price |
| SO+SB entity | System operator and single-buyer entity |
| SOEs | State-owned entities |
| SoLR | Supplier of last resort |
| SPP | Small power producer |
| SPPA | Standardised power purchase agreement |
| SPUG | Small Power Utilities Group (Philippines) |
| T&D | Transmission and distribution |
| tCO2e | Tonnes of carbon dioxide equivalent |
| TDRI | Thailand Development Research Institute |
| THB | Thai baht (currency) |
| TKDN | Tingkat Komponen Dalam Negeri (domestic content level requirement of PV) |
| ToU | Time-of-use rate |
| TPA | Third-party access |
| TransCo | National Transmission Corporation |
| TSO | Transmission system operator |
| TWh | Terawatt-hour |
| UC | Universal charges |
| UGT | Utility green tariff |
| USAID | United States Agency for International Development |
| USct/kWh | US dollar cents per kilowatt-hour |
| USD | US dollar (currency) |
| VAT | Value-added tax |
| VCGM | Viet Nam competitive generation market |
| VND | Vietnamese dong (currency) |
| VRE | Variable renewable energy (wind & solar) |
| VSPP | Very small power producers |
| VWEM | Viet Nam wholesale electricity market |
| WESM | Philippines wholesale electricity spot market |

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