ENERGY TRANSITION PARTNERSHIP

Powering Prosperity and Enabling Sustainability in South East Asia

REPORT

Enhancing the Spot Market to Attract Investments to Renewables

Deliverable 5: Impact Report on Increasing Participation of RE Generators in WESM

7 November 2025

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AR	Allocation Round (UK)
BESS	Battery Energy Storage System
CfD	Contract for Difference
CIS	Capacity Investment Scheme (Australia)
CSP	Competitive Solicitation Process
DOE	Department of Energy
DU	Distribution Utility
EC	Electric Cooperative
ECA	Economic Consulting Associates
EEG	Erneuerbare-Energien-Gesetz / Renewable Energy Sources Act (Germany)
ERC	Energy Regulatory Commission
ETP	Energy Transition Partnership
FIT	Feed-In Tariff
FIT-All	Feed-In Tariff Allocation
GEAP	Green Energy Auction Program
GEOP	Green Energy Option Program
GWAP	Generator Weighted Average Price
IEMOP	Independent Electricity Market Operation of the Philippines
IES	Intelligent Energy Systems
LCCC	Low Carbon Contracts Company (UK)
MW	Megawatt
MWh	Megawatt Hour
NCL	Nel Consulting Limited
NEM	National Electricity Market (Australia)
NGCP	National Grid Corporation of the Philippines
PEMC	Philippine Electricity Market Corporation
PHP	Philippine Peso
PSA	Power Supply Agreement
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Certificate
REM	Renewable Energy Market
REPA	Renewable Energy Purchase Agreement
RO	Renewables Obligation (UK)
ROC	Renewables Obligation Certificate (UK)
RPS	Renewable Portfolio Standard
SDG	Sustainable Development Goal
SGGP	Smart and Green Grid Plan
SO	Strategic Outcome
StrEG	Stromeinspeisungsgesetz / Electricity Feed-In Act (Germany)
UNOPS	United Nations Office for Project Services
VRE	Variable Renewable Energy
VREM	Voluntary Renewable Energy Market
WEM	Wholesale Electricity Market (Western Australia)
WESM	Wholesale Electricity Spot Market

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1 Executive Summary

This report has been prepared under the project "Enhancing the Spot Market to Attract Investments to Renewables". The project is implemented under the UNOPS Southeast Asia Energy Transition Partnership (ETP). The project is focused on facilitating increasing participation of renewable energy (RE) resources in the Philippines Wholesale Electricity Spot Market (WESM) by reviewing price mitigation measures and methodologies and analysing barriers and investment risks.

This report corresponds to Deliverable 5 under the project and covers the arrangements for support of RE in the Philippines and the prospects for increasing RE participation in the WESM. This is complementary to Deliverable 4 which looks at how increasing price caps in the WESM can support the development of RE generation. The analysis in this report is primarily drawn from a comparison of the experience with current approaches in the Philippines as against those in selected markets internationally.

RE support schemes in the Philippines are in the process of transitioning away from a fixed feed-in tariff (FIT) paid for energy purchased from RE generators, towards more market-based mechanisms which allow RE generators to "top-up" the revenues they receive from the energy market by also earning revenues from the sale of Renewable Energy Certificates (RECs). Distribution utilities (DUs) and suppliers are required to have sufficient RECs in each year, with each REC corresponding to 1 MWh of renewable energy, to meet their obligations under the Renewable Portfolio Standard (RPS), which specifies a proportion of energy purchases to be met from RE sources.

There are three main routes for generators to monetise RECs. They can participate in the Green Energy Auction Program (GEAP), under which Transco offers long-term contracts at a fixed price to buy energy and RECs. The energy is sold in the WESM and the RECs allocated proportionally to all DUs and suppliers. Differences between revenues from WESM sales and the contract price are recovered through the FIT mechanism as a universal charge. Generators can also sign power supply agreements (PSAs) with DUs and suppliers where they sell both energy and RECs at the contract price. Lastly, generators can opt to sell energy through the WESM and RECs through the renewable energy market (REM), which can be used by DUs and suppliers to purchase RECs to comply with their RPS obligations. DUs and suppliers can also sell RECs they have acquired through GEAP or PSAs in the REM.

The effectiveness of these mechanisms in supporting RE investment is questionable. REC prices are very low due to a combination of a price-cap based on the difference between average RE contract pries and WESM prices in recent years and to a large "overhang" of previously-issued RECs. This means the value to RE generators of REC sales is very small.

Internationally, the trend, as illustrated by the examples of Great Britain, Germany, and Australia, has been away from fixed support payments to all RE generators under RPS or similar mechanisms and towards mechanisms typified by:

- The use of market-based support mechanisms, with premium payments to offset the difference between market and contract prices.
- Procurement of renewable energy under support schemes through centralised, technology-specific, auctions.

This move has been driven by concerns over the rising costs of support schemes. The shift is expected to reduce these costs by only paying for those technologies that require support, and by not "over-paying" where, for example, the market price already exceeds the cost of the renewable energy technology.

In the Philippines, the trend could be seen as being in the other direction. The GEAP mechanism represents, in effect, a technology-specific auction with the equivalent of a two-way premium contract to adjust for differences between market and contract prices. However, in the longer-term, the intention is to substitute this with the RPS and accompanying REM, built around the use of universal support payments at a fixed rate through the requirement to purchase RECs.

This appears to open up two main options for the Philippines moving forward to enhance its support mechanisms:

- **Retain the GEAP** as the primary support mechanism, in line with international practice, but with reforms to improve its functioning. These would include increasing price-caps, conducting more frequent auctions, and other refinements to raise support prices and to increase flexibility for RE investors.
- **Continue to fully transition to the RPS and REM** but doing so while drawing on the lessons from international experience (notably Great Britain) as to cost containment. Central to this would be a move to raising prices for RECs (for example, imposing a buy-out price) and improving targeting (by banding REC issuance so that technologies which are less mature or competitive receive more RECs per MWh generated and vice-versa).

The impacts on customer costs are ambiguous. Both options would allow better targeting of support payments and so avoid paying RE generators which are already competitive. But both options would also imply a higher payment to those generators receiving support. The interactions between the mechanisms and WESM prices also need to be considered—a higher support payment may lead to lower WESM prices as generators recover their costs via the support mechanism, and so the net impact on customers may be zero or even a reduction in costs.

2 Introduction

1.1 Project Background

Intelligent Energy Systems Pty Ltd (IES), Economic Consulting Associates Ltd (ECA), & Nel Consulting Limited (NCL) have been selected by UNOPS to carry out the project titled “Enhancing the Spot Market to Attract Investments to Renewables”. The project is implemented under the UNOPS Southeast Asia Energy Transition Partnership (ETP).

ETP has four strategic outcomes: (SO-1) policy alignment with climate commitments, (SO-2) de-risking investments on energy efficiency and renewable energy, (SO-3) extending smart grids, and (SO-4) knowledge and awareness building. The project is focused on contributing towards SO-2 and SO-4 to facilitate increasing participation of renewable energy resources in the Philippines Wholesale Electricity Spot Market (WESM) by reviewing price mitigation measures and methodologies and analysing the barriers and investment risks to renewable energy (RE) deployment in the Philippines and energy self-sufficiency targets.

The expected long-term outcomes from this project are:

- Increase uptake of renewables in Philippines power system.
- Enhance understanding of opportunities for RE generators in the WESM to encourage greater level of investment in RE.
- Improve price mitigation measures to encourage investments into RE generation, increase market participation, and enhance market competition which lead to lower electricity tariffs.
- Strengthened capability of Philippine Electricity Market Corporation (PEMC) and Independent Electricity Market Operation of the Philippines (IEMOP) to monitor and analyse market and price trends, and recommended updates to price mitigating measures in the future.

1.2 ETP Role in Supporting the Energy Sector Transition in the Philippines

The ETP unites philanthropists and governments to collaborate with regional partners. ETP supports the switch to contemporary energy systems that can guarantee environmental sustainability and climate action, energy security, and economic prosperity. The ETP is currently focusing its support to the countries of Indonesia, Vietnam, and the Philippines to support in achieving the Paris Climate Agreement targets and in alignment with the UN Sustainable Development Goals (SDGs). Four interconnected strategic engagement pillars that are well matched to overcome the obstacles to energy transition form the foundation of ETP’s approach. These include:

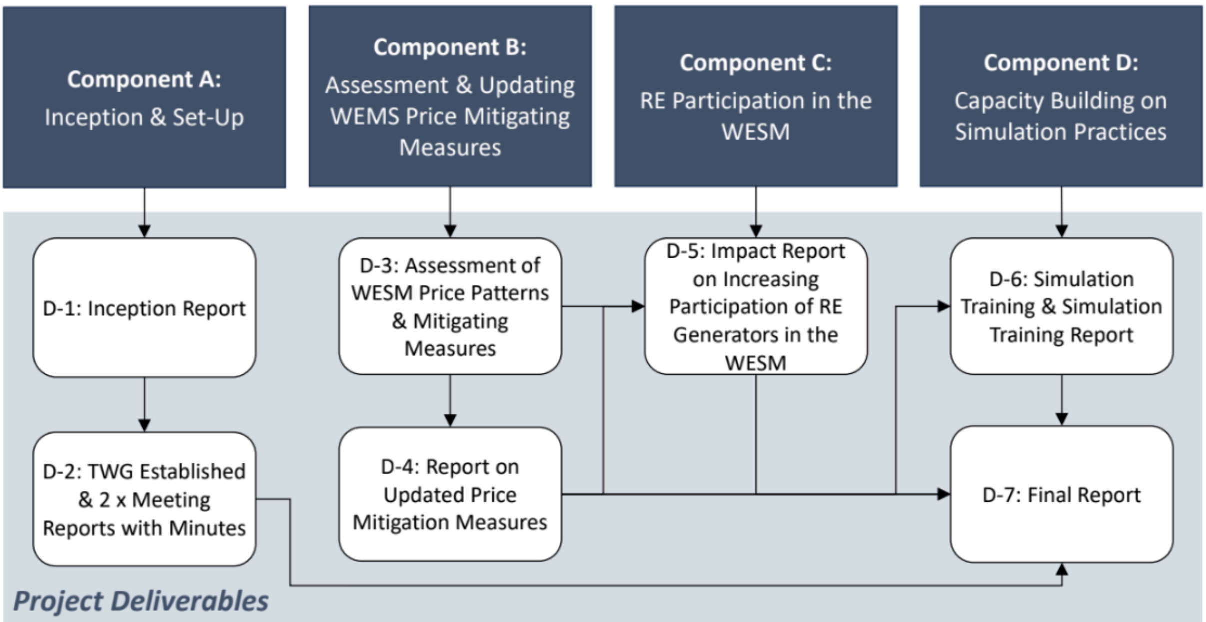
- Aligning policies with climate commitments,
- Reducing the risk associated with investments in renewable energy and energy efficiency,
- Expanding smart grids, and
- Expanding knowledge and awareness building.

1.3 Scope of Work

The project addresses the market barriers to renewable energy investments by assessing and updating the methodologies for setting price mitigating measures and recommending new cap values at balanced levels that will attract investments and at the same time protect consumers from high tariffs. The government has acknowledged that the current, outdated, and low price caps discourage investments in peaking generators leading to heavy reliance on aging fossil-based plants. The project will also analyse the opportunities for more renewables in the spot market and the risks to RE investments.

To achieve the intended outcomes and objectives, the project has been structured into four components: (1) Component A: Assessment of WESM Price Mitigating Measures, (2) Component B: Updating Price Mitigating Measures, (3) Component C: Analysis of RE Participation in the WESM, and (4) Component D: Capacity Building. The components and key deliverables / outputs for each component are illustrated in the following Figure 1.

Figure 1 Components and Deliverables



This report corresponds to Deliverable 5 and covers the arrangements for support of RE in the Philippines and the prospects for increasing RE participation in the WESM. This is complementary to Deliverable 4 which looks at how increasing price caps in the WESM can support the development of RE generation. The analysis in this report is primarily drawn from a comparison of the experience with current approaches in the Philippines as against those in selected markets internationally.

While the primary focus of the project is on RE participation in the WESM, in the context of the Philippines this cannot be separated from the renewable energy market used to support RE generators by paying additional revenues for their environmental characteristics. The two markets are inter-linked as lower WESM prices mean that RE generators need to earn more from the renewable energy market to compensate and vice-versa. This interaction has been a major driver for reform in RE support in the international examples discussed in this report, where there have been concerns that some RE generators are being "over-paid" by their ability to sell energy into one market and environmental characteristics into another, increasing costs for customers. Why this is and the reforms made to address the concern are covered in the relevant sections of this report.

1.4 Report Structure

The report for Deliverable 5 is structured as follows:

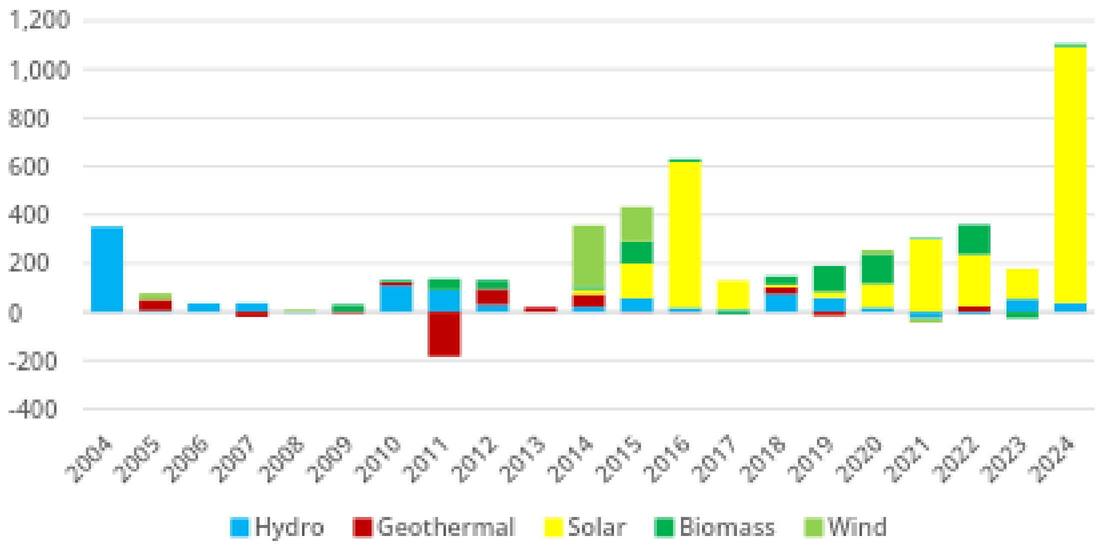
- Section 3 discusses the current levels of renewable energy deployment under these mechanisms and the barriers to increasing these.
- Section 4 reviews the current support mechanisms for RE investment in the WESM.
- Section 5 provides examples of international approaches to addressing these barriers and discusses their application to the Philippines.
- Section 6 summarises key findings and their implications for support schemes for RE generation in the WESM.

3 Status of renewable energy development

3.1 Renewable energy expansion

While renewable energy capacity in the Philippines has increased in recent years, excepting two solar-driven spurts in 2016 and 2024, additions have remained small (200-400 MW in most years).

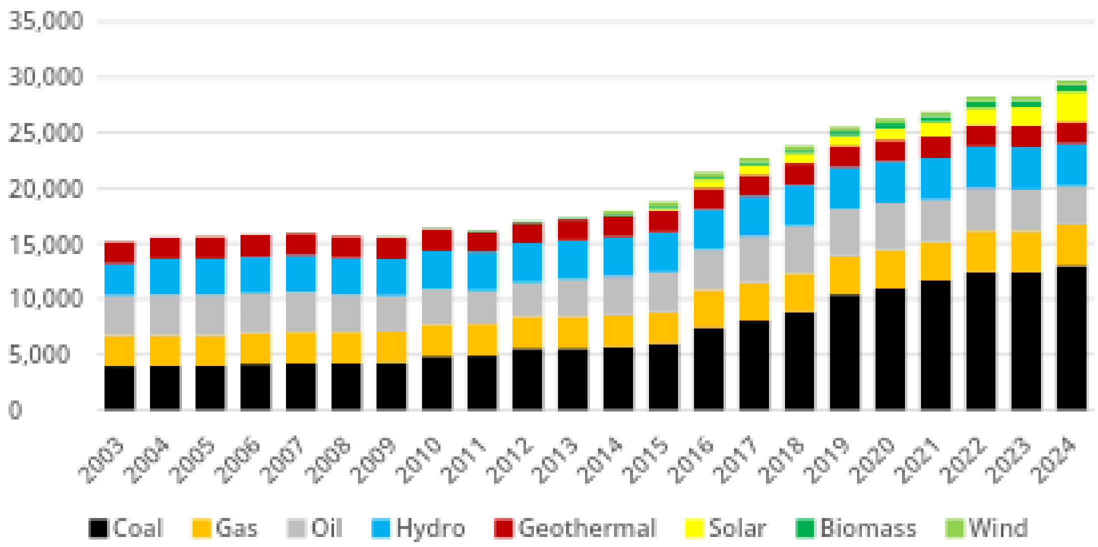
Figure 2 Renewable energy capacity additions by year (2003-24)



Source: Department of Energy. 2025. Power Statistics 2024. Note: The 2011 geothermal capacity reduction is not explained

As a consequence, the expansion of renewable energy capacity has only just been sufficient to maintain its share of total generating capacity at around 30% over time, rather than expanding.

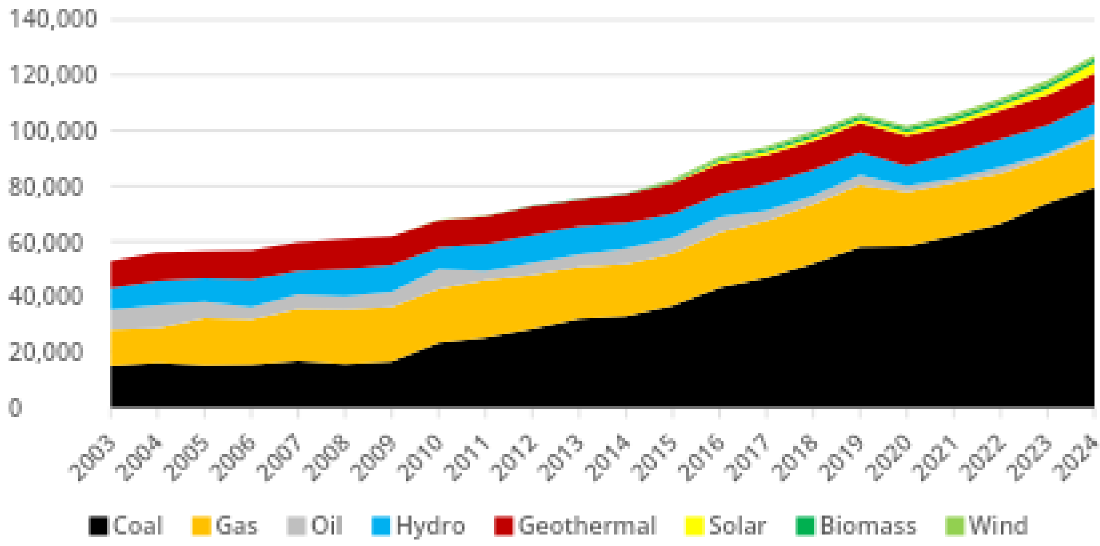
Figure 3 Installed capacity, on-grid (2003-24)



Source: Department of Energy. 2025. Power Statistics 2024

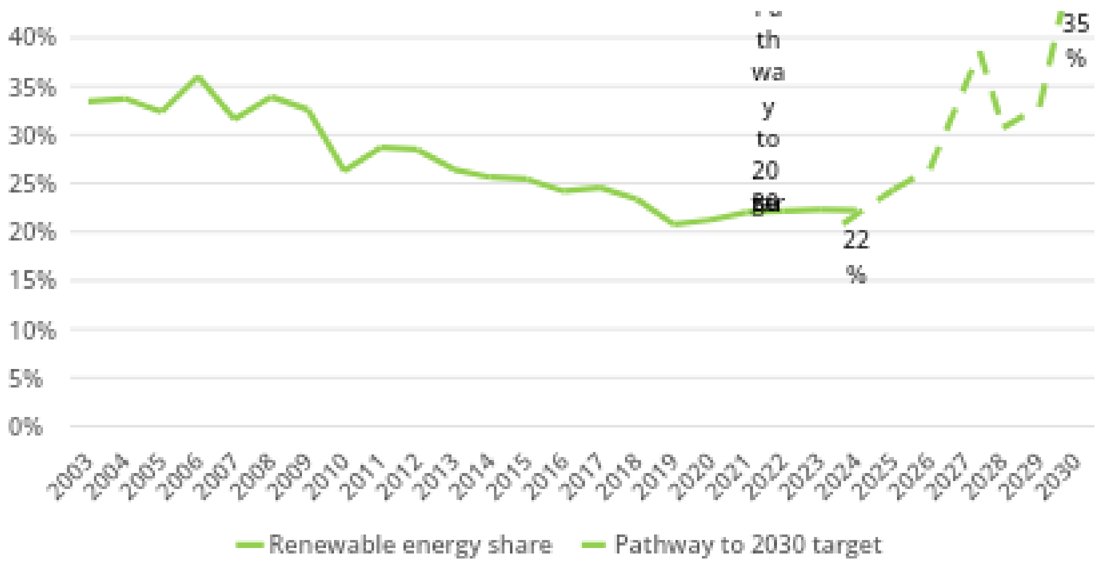
With much of the capacity additions that have taken place being in the form of solar PV, operating at lower capacities, this outcome has seen the share of renewable energy generation declining over time. From a peak of 36% in 2006, renewable energy represented only 22% of generation in 2024. This places it significantly short of the target of 35% share by 2030 (and 50% by 2040) and highlights the urgent need for mechanisms to support rapid renewable energy deployment and to overcome barriers to investment.

Figure 4 Electricity generation, on-grid (2003-24)



Source: Department of Energy. 2025. [Power Statistics 2024]

Figure 5 Renewable energy share in generation, on-grid (2003-24)



Source: Calculated from Department of Energy. 2025. [Power Statistics 2024]

3.2 Revenue adequacy and revenue certainty

The discussion of barriers in this report, consistent with its scope, focuses on barriers to RE investment directly related to the ability of these generators to be fully remunerated through energy sales. For the purposes of this report, these are separated into potential barriers to:

- **Revenue adequacy**, the ability of RE generators to recover their costs from sales, both currently and in future.
- **Revenue certainty**, the ability of RE generators to deliver the secure cash flows needed to obtain financing.

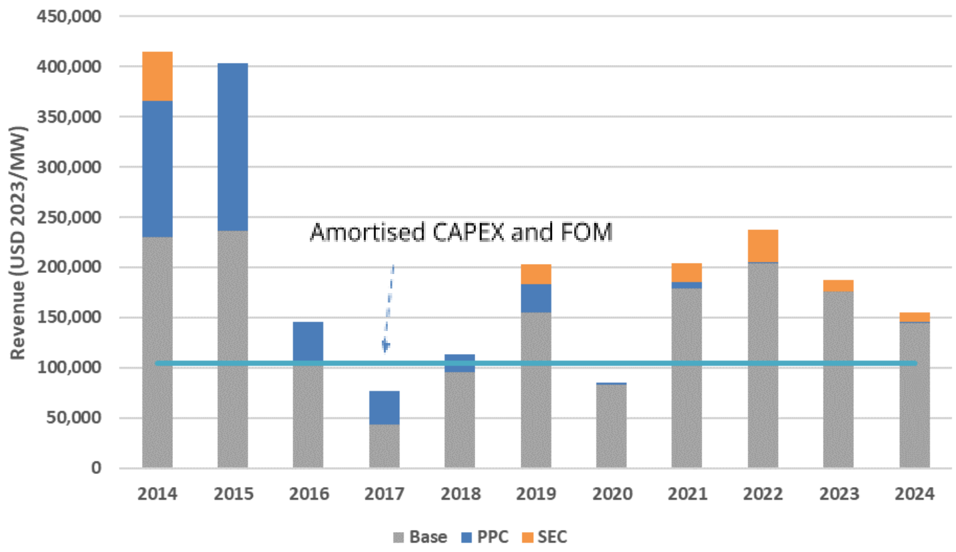
This report does not consider the question of whether current WESM primary and secondary price-caps deter investment, as this is addressed under the separate Deliverable 4 report. That report concludes that the current price-caps do not necessarily prevent RE generators recovering their costs. However, they may make it difficult for assets which provide the necessary flexibility to integrate variable renewable energy (VRE) supply, such as storage and peaking gas turbines, to recover their costs which, in turn, will make it more difficult to accept new wind and solar generation onto the grid.

There are also significant non-market barriers, which can help explain some of the delays in increased RE generation. These include permitting constraints and delays and, noticeably, the slowness of the buildout of the necessary grid infrastructure to accommodate new RE generators (a problem not unique to the Philippines). Measures are being taken to address the latter, with the Department of Energy (DOE) becoming more actively involved in providing strategic direction for the Transmission Development Plan, prepared and implemented by the National Grid Corporation of the Philippines (NGCP), the transmission concessionaire. Since May 2023, DOE has been working to develop a Smart and Green Grid Plan (SGGP) including envisaging the 2050 transmission system. DOE is also more closely monitoring delivery of projects and exploring options for the state-owned Transco to develop critical and priority transmission projects.

3.2.1 Current revenue adequacy

The available data suggests that solar generators are currently able to recover their costs from energy sales alone. The position is more tenuous for wind. Figure 6 and Figure 7, below, show a comparison of estimated WESM spot market revenues relative to costs for solar and wind generation from 2014 to 2024. Ignoring the Covid-impacted year of 2020, revenues to solar generators covered costs in nine out of ten years but, for wind, only six out of ten years (including the most recent four years).

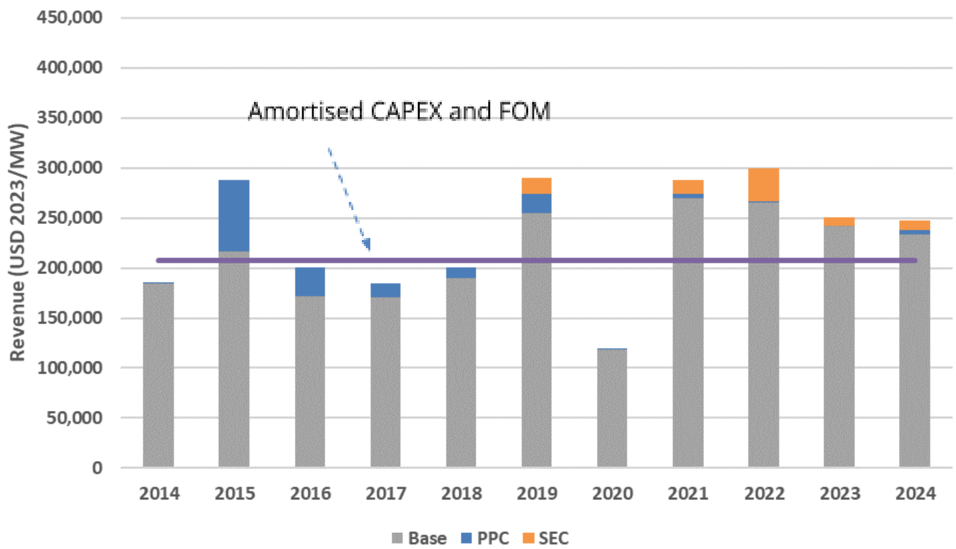
Figure 6 Solar Revenue Adequacy



Note: For comparative purposes, at a capacity factor of 18%, annual revenue needs of 100,000 $/MW for solar convert to ~63 $/MWh (~3,700 PHP/MWh).

Source: IES et al. 2025. Deliverable 4: WESM Price Mitigation Revenue Impacts

Figure 7 Wind Revenue Adequacy

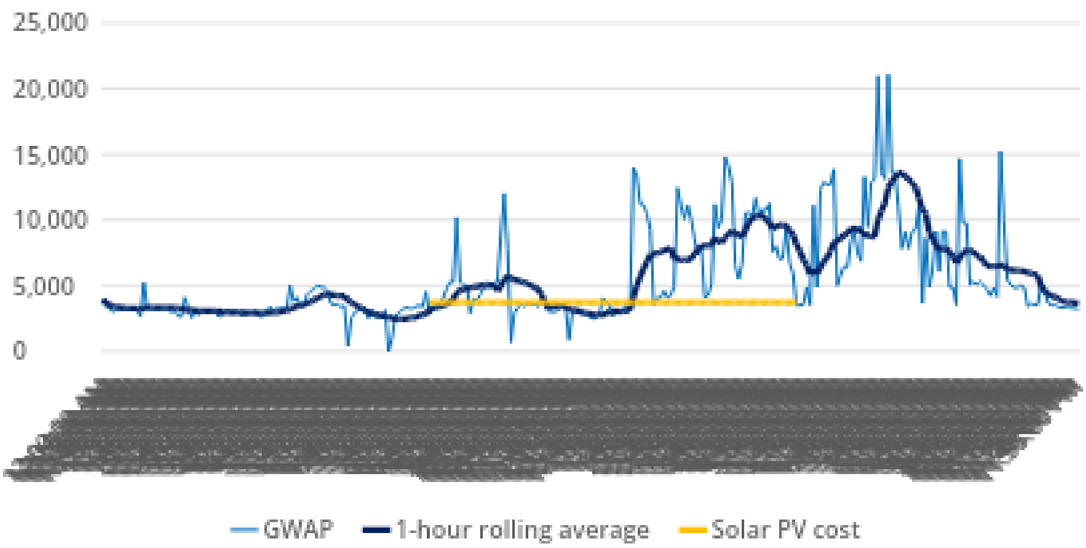


Note: For comparative purposes, at a capacity factor of 35%, annual revenue needs of 205,000 $/MW for wind convert to ~67 $/MWh (~3,900 PHP/MWh).

Source: IES et al. 2025. Deliverable 4: WESM Price Mitigation Revenue Impacts

The higher revenues seen for solar are explained by its daytime operation, when WESM prices tend to be higher, compared to wind which more frequently generates at night. This pattern is illustrated below for an example day, where prices in the afternoon significantly exceed the estimated cost of solar generation (amortised capital expenditure and fixed operating and maintenance costs).

Figure 8 WESM prices (system GWAP) and solar costs, 8 July 2025

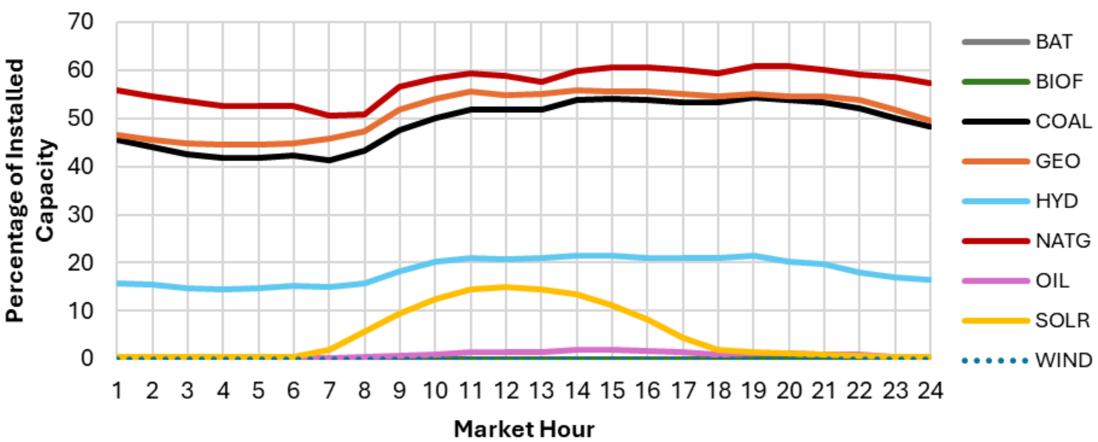


Source: IEMOP. Generator-Weighted Average Price (Final). 8 July 2025

3.2.2 Current revenue certainty

The same breakdown of routes to market suggests that solar and, to a smaller extent, hydro projects are more willing to accept higher exposure to WESM prices, and so lower revenue certainty. This is presumably due to their high upside potential due to their low costs relative to prevailing WESM prices. This is reinforced by data on current contracting coverage. In 2023, hydro generators were contracted for only around 20% of their capacity and solar generators for 15% (Figure 9).

Figure 9 System-wide Average Contract Profiles (2023)



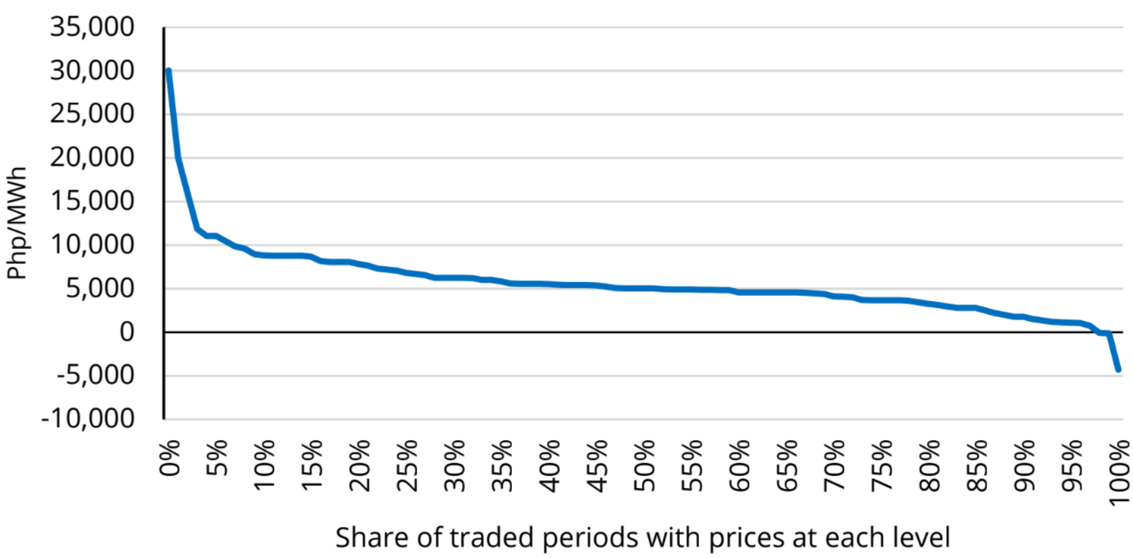
Note: The generator technologies that are currently registered in the WESM are Battery Energy Storage Systems (BAT), Biofuels (BIOF), Coal-fired (COAL), Geothermal (GEO), Hydroelectric (HYD), Natural Gas (NATG), Oil-based (OIL), Solar (SOLR) and Wind.

3.2.3 Potential future developments

At present, revenue adequacy and certainty do not seem to be major concerns for investment in solar power and, to a lesser extent, small-scale hydro power. However, there are a number of reasons, drawing on both trends in the Philippines and on international experience, to believe this situation may not persist:

- The growing solar share in generation will tend to push market prices lower, even into negative pricing territory, in the middle of the day. This will make it ever more challenging for solar power generation which relies on WESM sales to recover its costs unless supplemented by out-of-market payments. Modelling conducted for this current assessment suggests that, by 2030, WESM prices will be negative in around 3% of hours or for 260 hours per year (Figure 10).
- The growing solar share will also increase concerns about the impacts of high shares of intermittent and variable renewable energy generation on system security and reliability. In turn, this is likely to increase the trend towards requiring hybrid solar and battery energy storage systems (BESS) plants which can 'firm' their output and which can respond to dispatch instructions. This will push up costs for new projects, making them less competitive in the WESM.
- Currently, most investment has come from domestic conglomerates borrowing from domestic banks, who rely on existing track records and relationships to assess credit risk.[1] Expanding the pool of project developers and sources of finance will likely mean a greater need for non-recourse financing which is supported by bankable, long-term, PPAs with creditworthy off-takers.

Figure 10 Luzon WESM price duration curve (2030, forecast)



Notes: Patterns are similar for Visayas and Mindanao. Scenario 1 shown

Source: IES et al. 2025. Deliverable 4: WESM Price Mitigation Revenue Impacts

If the Philippines is to continue to expand RE generation, as targeted, and to expand beyond its dependency on solar power to meet targets, then it will be necessary to:

[1] EY. 2023. Understanding Barriers to Financing Solar and Wind Energy Projects in Asia

- Increase non-WESM payments to renewable energy generators, to compensate for expected falls in WESM prices over time.
- Increase the certainty of revenues, to enable access to a wider and deeper pool of developers and financing sources.

The following section discusses the RE support schemes in place in the Philippines, which are intended to address these needs for out-of-market revenues and for revenue certainty.

4 Current renewable energy support mechanisms

4.1 Overview

Renewable energy support mechanisms in the Philippines, as in many other countries, have evolved over time. Initially, financial support was provided in the form of a fixed price for energy purchased from RE generators, in the form of a Feed-In Tariff (FIT). Subsequently, this has moved towards more market-based mechanisms. These are based around allowing RE generators to "top-up" the revenues they receive from the energy market by also earning revenues from the sale of Renewable Energy Certificates (RECs) representing the "clean" attributes of the energy they produce.

The value of RECs can be monetised through compliance or voluntary routes. Generators can sell these to suppliers who use them to demonstrate their compliance with the Renewable Portfolio Standard (RPS) which requires mandated participants to meet a minimum share of energy purchases from RE generators. They can also sell them directly to eligible customers on a voluntary bilateral basis.

Renewable energy generators also benefit from priority dispatch arrangements. In the absence of local constraints, this should ensure that they are always able to sell their outputs into the WESM, at the prevailing market price in each period.

4.2 Feed-In Tariff

The FIT mechanism was introduced in 2010 under the Renewable Energy Law of 2008 (RA9513). It pays a fixed price for energy purchases from RE generators. Quotas apply to the quantity of each technology type eligible for the FIT. As of December 2023, the quotas have been exhausted for all technologies other than run-of-river hydroelectric plants, where 167 MW remains unsubscribed.[2]

The costs of FIT payments are recovered from customers through the FIT-All mechanism, a levy per kWh applied to all customers. Generator under the FIT sell their energy into the WESM. The proceeds from these sales are paid to the FIT-All fund administered by the state-owned utility, Transco. The fund then pays the FIT revenues to the RE generator. Shortfalls between the FIT payments and WESM revenues are covered by a FIT-All levy applied to distribution utilities[3] (DUs) for captive customers and suppliers to the contestable market[4] on a uniform PHP/kWh basis.

4.3 Renewable Energy Certificate mechanisms

4.3.1 Renewable Portfolio Standard

The RPS was also introduced under the 2008 Renewable Energy Law, to support the achievement of the National Renewable Energy Program's targets of a 35% share of RE generation by 2030 and 50% by 2040. Mandated participants, comprising DUs for captive customers, suppliers for customers in the contestable market, and generators supplying directly connected customers, are required to surrender RECs (with each REC corresponding to one MWh of RE generation) covering a minimum percentage of their net sales.

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2 DOE. 2024. Philippine Energy Plan 2023-2050: Volume II

3 Distribution utilities are defined as electric cooperatives, private corporations, government-owned utilities, and local government units, with exclusive franchises to operate distribution systems.

4 These include the non-regulated business segment of DUs serving the contestable market.

The initial requirements were set in 2017 at an annual 1% increment in the RE share of supplier sales starting from a 2018 base level.[5] In 2022, this was increased to an annual 2.52% increment from 2023 onwards and a 2019 base was adopted. By 2030, this delivers an RPS of 26.5%, an increment of 23.2 percentage points on the base level.[6]

DUs and suppliers can obtain RECs to demonstrate their compliance through three main routes:

- Under the FIT-All mechanism, RECs from generators paid through the mechanism are distributed to DUs and suppliers proportionally to their contributions to the FIT-All fund (ie, a DU paying 10% of the fund's income from the FIT-All levy would receive 10% of the RECs created by RE generators paid from the fund).
- DUs and suppliers can contract directly with RE generators, using power supply agreements (PSAs) with the agreement also giving the right to the RECs created alongside the generated energy. For captive customers, any such procurements must comply with the competitive solicitation process (CSP) laid down by the Energy Regulatory Commission (ERC) and the final PSA price and terms must be approved by ERC.
- DUs and suppliers can also buy unbundled RECs from RE generators, other DUs and suppliers, and third parties, through the Renewable Energy Market (REM), as described below.

Failure to comply with the RPS attracts an administrative penalty on mandated participants of PHP 100,000 to PHP 500,000 or the revocation of the supplier's licence.[7] This is a relatively small sum and may not provide effective incentives to ensure RPS compliance. For Meralco, serving the greater Manila area, for example, the higher penalty translates to a cost of just 0.02 PHP/MWh (0.0003 $/MWh). Even for a much smaller utility, such as BLI serving Bohol, the higher penalty represents 4.8 PHP/MWh (0.08 $/MWh). This represents the upper bound on what these DUs might be expected to pay for RECs, if ignoring other incentives such as the positive reputational benefits of purchased RECs.

4.3.2 Green Energy Auction Program

The Green Energy Auction Program (GEAP) has been developed by DOE as a mechanism to assist DUs and suppliers to comply with the RPS, replacing the previous FIT.

The GEAP procures quotas for different technologies and regions. The product procured is the bundled energy and REC (ie, procuring one MWh of energy also procures the associated REC). Both new generators and existing generators are eligible to participate. Participation by existing generators is limited to those built after the date of the Renewable Energy Act 2008, or to incremental or additional capacity added after the date of the act to pre-existing generators. Generators are selected on a least-cost basis with their tariff being established on a pay-as-bid basis.

Generators selected through GEAP sign a 20-year Renewable Energy Purchase Agreement (REPA) with Transco. Currently, these generators are then included in and remunerated through the FIT-All mechanism. The REPA functions in effect as a two-way contract for differences (CfD) where the generator receives the contract price and differences between this and the price received for sales in the WESM are covered by the FIT-All charge. RECs created by RE generators procured

[5] The discussion here relates only to the on-grid RPS. There is also an off-grid RPS but this does not cover sales through the WESM, which is the focus of this report.

[6] IEMOP. July 2025. June 2025 Market Operations Highlights

[7] In 2023, DOE amended this so that mandated participants can be penalized the costs avoided by noncompliance, if higher. However, it is not clear how this difference would be calculated and applied in practice.

through GEAP are allocated between DUs and suppliers in the same way as for those created by RE generators with an FIT.

A consequence of this is that DUs and suppliers do not have the ability to opt-out of the GEAP (as they are automatically included through the FIT-All mechanism). This means that there is little reason for DUs and suppliers to procure RECs from new projects individually, either through bilateral PSAs or through the REM, as they would still be included in the FIT-All and the total RECs allocated through this route are targeted to be sufficient to meet RPS requirements. However, in the longer-term, the intent is to convert the GEAP to an opt-in mechanism, where DUs and suppliers can choose whether to participate or whether to adopt different procurement routes (with their FIT-All contributions being adjusted accordingly).

Two GEAP rounds have been completed, in 2022 and 2023. Currently, DOE is conducting the third, fourth and fifth GEAP rounds for large-scale hydro and geothermal projects, solar and onshore wind, and offshore wind respectively. A summary of the outcomes in the first two rounds (GEAP 1 and GEAP 2) is provided below.

Table 1 GEAP results

Reference	Capacity (MW)		Average price [a]
	Quota	Award	
GEAP 1 (2022)			
Hydro run-of-river	130	99 (76%)	5,424 PHP/MWh (93.1 $/MWh)
Biomass	230	3 (1%)	5,070 PHP/MWh (87.0 $/MWh)
Solar PV [b]	1,260	1,454 (115%)	3,647 PHP/MWh (62.6 $/MWh)
Onshore wind	380	374 (98%)	4,411 PHP/MWh (75.7 $/MWh)
GEAP 2 (2023)			
Biomass	230	0 (0%)	n/a [c]
Solar PV [b]	7,620	1,978 (26%)	n/a [c]
Onshore wind	3,720	1,462 (39%)	n/a [c]

Notes:

(a) Capacity-weighted

(b) "Solar" includes ground-mounted, roof-mounted, and floating solar PV

(c) Winning bid prices not published

Source: Department of Energy. Green Energy Auction Program in the Philippines

An earlier review of the GEAP under ETP funding identified a number of potential areas for improvement[8]:

[8] Kuungana Advisory. May 2024. Diagnostic for Competitive Arrangements for Energy Transition: Final Report

- The gap between procured capacity and quotas evident in the GEAP 2 auction is attributable to reserve prices being set below the costs of investments in some cases and to unrealistically early commissioning date requirements. The review suggested revisiting both auction parameters. While the reserve prices for more recent rounds are not known, the third, fourth, and fifth rounds do provide for longer lead times for projects.
- Quotas may be unnecessarily high. The first two auction rounds alone, if all quotas were filled, would have procured sufficient capacity to fully meet the 2030 target for RE generation share. The review suggested smaller and more frequent auctions may be more efficient.
- The REPA is a short document with many terms and conditions incorporated by reference to various circulars and other regulations. While this may be acceptable to domestic investors familiar with such arrangements, it may deter international investors. The review suggested transitioning the REPA to a more conventional Power Purchase Agreement (PPA) incorporating standard protections for investors (such as for curtailment and changes in law).

The GEAP results are used to establish a cap on the accepted tariff for purchases from RE generators through the CSP, meaning that they effectively establish the maximum price for all new RE generation purchased by DUs for sale to captive customers.

4.3.3 Green Energy Option Program

Under the Green Energy Option Program (GEOP), contestable customers with peak demand exceeding 100 kW can opt to procure part or all of their energy from RE sources, through a designated RE supplier. Such purchases also entitle the customer to the corresponding RECs. The tariffs for such purchases are established bilaterally but are expected to be at a premium to the WESM price due to the bunding with the REC, which enables the customer to demonstrate that they meet their electricity needs from "clean" sources.

4.3.4 Renewable Energy Market

The REM provides a platform for trading RECs between RE generators, suppliers and DUs to enable the latter two groups to demonstrate their compliance with the RPS. It is managed by the Independent Electricity Market Operator of the Philippines (IEMOP), who also manages the REC registry. All DUs and suppliers and all WESM-participating and off-grid RE generators wishing to issue RECs must participate in the REM. Other generators (including legacy plants), end-users with their own RE facilities, and RE facilities participating in GEOP may voluntarily participate. The REM for compliance with the RPS became fully operational on 26 December 2024. A voluntary REM (VREM) is under development.

With the REM, RECs are initially allocated as follows:

- RECs created by generators under the FIT-All mechanism are allocated proportionally to mandated suppliers and DUs in the REM.
- RECs created by generators with a PSA with supplier or DU are allocated to the supplier or DU.
- RECs created by other generators are allocated to the generator.
- RECs created by generators voluntarily participanting under net metering or own-use belong to the host DU and otherwise to the generator.

REM traded volumes are currently relatively low, with offers to sell exceeding bids, and prices are consequently also low. In July 2025, 216,154 RECs were purchased in the REM, with over 90% of these being by unregulated entities (retail suppliers and generators purchasing for customers opting for green tariffs), representing of all RECs generated in the month.[9] The average price paid was 71 PHP/MWh (1.2 $/MWh).

This low price comes about despite issuance falling short of requirements. In 2024, total electricity generation was 126,341 GWh and the RPS was set at 11.38%, implying that 14.4 million RECs were required for compliance. Actual issuance of RECs in the year was 8.7 million.[10] This discrepancy between excess demand but low prices may be partly explained by an "overhang" of RECs issued in previous years. As of July 2025, 52,133,867 RECs were registered, representing the equivalent of 22 months of total renewable energy generation. RECs are invalid after three years from issuance meaning that this overhang should gradually diminish with demand pushing REC prices up towards the price-cap.

4.3.5 Renewable Energy Certificate Price Cap

A price-cap applies to REC trades within the compliance REM. This in effect also sets the cap on prices in the GEAP, as buyers through that program are unlikely to be willing to pay more for bundled energy and RECs than they would need to pay if procuring energy separately and the RECs through the REM. The REC Price Cap is also likely to represent the effective cap on voluntary sales of RECs to customers through the GEOP and REM. If these voluntary markets were to pay above the price-cap, RE generators can be expected to opt to sell through these markets until the price is driven down to the same level as in the compliance markets, (ie, the REC Price Cap).

The REC Price Cap is set as the difference between the evidenced cost of power purchases from RE generators, in approved PSAs, less the market price and so captures the premium required to make RE generators viable. The cap was initially set as the second highest approved PSA price between 2017 and 2019 less the generator-weighted average price (GWAP) over the period from 26 December 2016 to 25 December 2019. In 2024, it was reset as the capacity-weighted average PSA price for RE generators commissioning since the Renewable Energy Act less the GWAP between 26 December 2018 and 25 December 2023.[11]

The first calculation established a price-cap of 5,044 PHP/MWh (86.9 $/MWh) and the second calculation a cap of 241.56 PHP/MWh (4.2 $/MWh), or some 95% lower. The reduction is roughly equally due to a fall in the RE generation PSA price used (resulting from the shift from using the marginal to average PSA price), and to the use of a higher GWAP (resulting from the inclusion of the 2022-23 period when fossil fuel prices and so generation costs rose sharply). It should be noted that the revised value is of a similar order of magnitude to prices seen for International RECs in other emerging markets in South-East Asia.[12]

As the cap is an *average*, it does not reflect the support needs of any individual technology. Consequently, it is likely to be too low to make less mature and most costly technologies viable, while "overpaying" established technologies with low costs.

9 IEMOP. August 2025. July 2025 Market Operations Highlights

10 IEMOP. August 2025. July 2025 Market Operations Highlights

11 ERC Resolution No. 08 Series of 2024

12 For example, I-REC prices for Malaysian solar were reported as 5.55 $/MWh in February 2025 and for Viet Nam solar as 0.44 $/MWh in 2025 H1. (Argus. 10 March 2025. I-Rec, I-Track demand soars in Feb alongside supply | Hestiya. 12 August 2025. Vintage 2025 and Vintage 2024 I-RECs - Market Insights for H1))

4.4 Summary of current support schemes

To date, RE support schemes in the Philippines have largely operated in practice through the FIT-All mechanism (initially directly as an FIT and subsequently through the GEAP which functions in a similar manner). Under this, a central, state-owned, counterparty contracts for RE generation and recovers the difference in costs between contract prices and market prices through a levy on all captive customers.

The FIT-All mechanism has been the main route to market for new biomass and wind capacity, and for around half of hydro capacity (Table 2). It has been much less significant for solar capacity expansion, reflecting its current ability to recover costs from WESM revenues alone.

Table 2 REC-eligible generating capacity (April 2025)

Technology	REC-eligible capacity (MW)			
	FIT-All [a]	Bilateral [b]	WESM [c]	Total
Biomass	257	0	93	350
Geothermal	0	208	43	251
Solar	541	687	1,191	2,419
Hydro	221	82	229	532
Wind	426	17	0	443

Notes:

REC-eligible capacity captures most new RE generating capacity added post-2008.

(a) Includes "FIT system", "CEO-FIT", "COE-GET"

(b) Includes "Non-FIT (Bilateral Agreement)" and "Non-FIT (QTP)"

(c) Includes "Non-FIT (under WESM)", "Non-FIT" without further description, and could not be identified

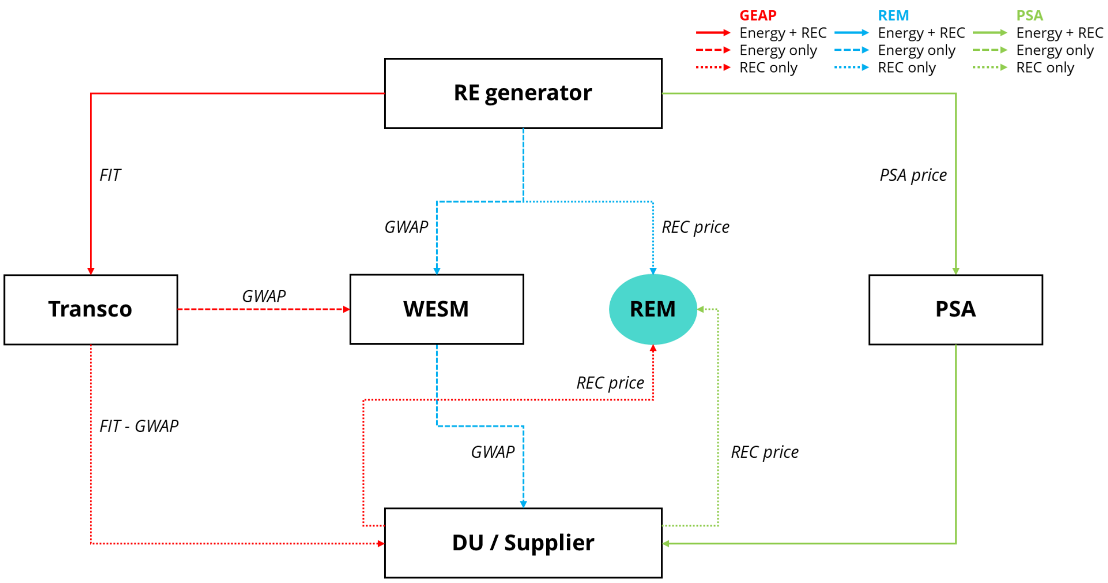
Source: Department of Energy. 30 April 2025. Eligible RE Power Plants for Renewable Portfolio Standards (RPS) Compliance for On-Grid and Off-Grid Areas

The Philippines is transitioning from the FIT-All mechanism towards a RPS-based framework. Under this, support for RE generation comes through both compliance and voluntary routes:

- The compliance route is built around the RPS. An increasing RPS target should drive up the demand for RECs and their price, thereby generating the additional revenues required to make new RE generation viable.
- There is expected to be a shift from centralised procurement under the FIT-All mechanism to bilateral contracting by DUs and suppliers with RE generators. This will be accompanied by increased unbundling of RECs and energy, with the former being traded separately on a bilateral basis and through the REM.
- A centralised auction will continue but on an opt-in basis and with direct contracting between participating DUs and those RE generators selected in the auction. We assume that this would primarily be targeted at smaller DUs who want to minimise transactions costs of procuring RECs themselves.
- Customers will also be able to voluntarily increase the share of renewable energy in their supply mix, by selecting RE suppliers under the GEOP and/or purchasing RECs through the voluntary REM. This will provide a potential source of additional revenues for RE generation not needed to meet the RPS targets.

A simplified representation of the support schemes is provided below.

Figure 11 RE support schemes in the Philippines



Source: Consultant. GEOP is not shown

A summary of the roles of major entities in the various RE support schemes as shown is provided below.

Table 3 Responsibilities of entities

Entity	Responsibilities
Department of Energy	• Issues regulations on RE support schemes • Set RPS requirements and enforce compliance • Conduct GEAP auctions • Determine REC eligibility and price-cap
Energy Regulatory Commission	• Establish Competitive Solicitation Process for PSA procurement • Approve PSAs with DUs
Transco	• Sign REPAs awarded through GEAP • Manage FIT-All mechanism
IEMOP	• Operate WESM • Manage REC registry • Operate REM
Mandated participants (DUs / suppliers)	• Purchase RECs to comply with RPS (via FIT-All or REM or PSAs)

Source: Consultant

4.5 Assessment

Challenges that arise in the context of the Philippines with respect to using these evolving schemes to support large-scale RE expansion are:

- **Low REC prices**. Currently, there appears to be an oversupply of RECs relative to demand, which keeps prices low. Even without this oversupply, the relatively low REC price-cap means that revenues from REC sales remain small.
- **Lack of incentives for long-term contracting**. The incentives for DUs to enter into long-term contracts to fix the prices of REC purchases, which then provide revenue certainty for RE generators, are weak. The current REC price cap means that DUs can be confident of being able to purchase RECs for future RPS compliance at low prices as and when needed. If they are unable to do so, the low penalties payable for non-compliance with the RPS means that this is unlikely to be seen as a significant risk.
- **Limited number of creditworthy offtakers**. The Philippines has 147 DUs. The vast majority (121 in number) are Electric Cooperatives (ECs), most of which are both small in size and in a weak financial position[13]. The implication is that, if DUs did have strong incentives to contract long-term with RE generators, only a small number are likely to be perceived as being creditworthy counterparts by lenders and so able to enter into such contracts.

[13] As of 2025 Q1, 25% of ECs had less than one month's working capital, 11% were in arrears in payments to generating companies, and 39% were making operating losses. (National Electrification Administration. 2025. Compliance Report on the Performance of Electric Cooperatives: 1st Quarter of 2025)

5 International experience

5.1 Overview

As the Philippines transitions towards more market-based support schemes, the challenges it will face include:

- Ensuring that REC prices are high enough and stable enough to make new RE generation financially viable while, at the same time, not becoming unduly costly for customers.
- Providing appropriate incentives for long-term contracting by DUs to provide the necessary revenue certainty for investors in RE generation.
- Addressing the lack of creditworthiness of many DUs which limits their ability to contract long-term.

This section reviews international experience in providing market-based RE support mechanisms, with a focus on wind and utility-scale solar generation. Rooftop solar is excluded.

The review focuses on the examples of:

- **Great Britain**, which has transitioned from a RPS model to the use of long-term CfDs signed with a government-backed entity. The reasons for making this change are particularly relevant in the context of the challenges in the Philippines and this represents one possible way forward.
- **Germany**, which applies FITs but has continually adjusted these to maintain an appropriate balance between costs and support needs. How this has been done can provide lessons for the Philippines in how to further refine the FIT-All mechanism if this is a preferred way forward. Germany is moving from FITs to market-based mechanisms, which further illustrates the issues with long-term reliance on FIT mechanisms.
- **Australia**, where the focus has been on how to address issues of revenue certainty for utility-scale generation, to support financing in a market where revenue adequacy has generally been sufficient for utility-scale projects and so mechanisms such as FITs have not been required. In the case of the Philippines this provides possible lessons in how, for example, to encourage investment in technologies such as utility-scale solar which are already competitive at current electricity market prices.

5.2 Great Britain

5.2.1 Overview of the Renewables Obligation

The Renewables Obligation (RO) was introduced in Great Britain in 2002 and extended to Northern Ireland in 2005.[14] The RO operates as an RPS:

- Suppliers of electricity are obliged to purchase a given share of their energy requirements from renewable energy sources.
- Compliance with this requirement is demonstrated by surrendering Renewable Obligation Certificates (ROCs) to cover their renewable energy obligation. ROCs are tradeable instruments. A registry of issued ROCs is maintained by the energy regulator, Ofgem.

[14] For conciseness, all subsequent discussion in this section relates to the RO in Great Britain (England, Scotland, and Wales) alone.

- Eligible generators are able to issue ROCs for a 20-year period, thus providing them with an additional revenue stream from the sale of these certificates.
- Suppliers who submit insufficient ROCs to cover their obligation are required to purchase the shortfall at an administered buy-out price. The proceeds are paid into a buy-out fund.
- The buy-out fund is used to cover the costs of Ofgem in administering the RO. Any surplus after these payments is redistributed to suppliers in proportion to their share of total ROCs surrendered (for example, a supplier who surrendered 10% of all ROCs in a year would receive 10% of the buy-out fund less Ofgem's costs). [15]

The RO scheme was closed to all new generators in 2017 (with earlier closure dates of 2016 for onshore wind and in 2015 for solar), for reasons discussed below. However, it remains in operation until all generators accredited under the scheme have reached the 20-year limit for issuing ROCs.

The target renewable energy share under the RO was initially set at 3% of generation. It was gradually increased to 15.4% at the time of closure. The actual obligation can be higher than this, as discussed below. The buy-out price was set at £30.0/MWh at the start of the RO in 2002/03. This is indexed to inflation and has reached £67.06/MWh for 2025/25 ($89.2/MWh).

For the most recent completed year, 2023/24, key statistics for the RO are[16]:

- 107.4 million ROCs were generated by accredited renewable energy producers, covering 35.4 GW of capacity[17] and 78.2 GWh of generation (31.5% of the UK total).
- The largest share of capacity was represented by onshore wind (35%), followed by biomass (25%), offshore wind (19%), solar PV (17%), and others (5%).
- 103.9 million ROCs were surrendered by suppliers, covering 91.7% of the total obligation in the year of 114.5 million ROCs.
- At the 2023/24 buy-out price of £64.96/MWh, the total value of payments under the RO was a notional £6.7 billion ($8.9 billion).
- £617 million was redistributed to suppliers from the buy-out fund, equivalent to £5.95/MWh ($7.9/MWh) per surrendered ROC.

5.2.2 Issues with the Renewables Obligation

The RO closure and replacement came about due to issues experienced in its operation:

- The risk that, if the number of ROCs issued exceeded the RO, then ROC prices would collapse. This acted as a deterrent to investment in further renewable energy capacity as the share of renewable energy approached the RO target value. This was addressed through revisions to the calculation of the total obligation in a year to take account of the level of ROC issuance, but these changes also increased the costs of the scheme.
- Concerns that the RO was paying too much for established renewable energy technologies which needed less support, while not providing sufficient incentives for less mature technologies which the government was keen to promote. This was partly

[15] This can lead to traded ROC prices exceeding the buy-out price as buyers of ROCs will both avoid the buy-out requirement and receive a payment from the buy-out fund.

[16] Ofgem. 2025. Renewables Obligation Annual Report: Scheme Year 22 (1 April 2023 to 31 March 2024). This data includes Great Britain and Northern Ireland.

[17] Of this, 0.3% is represented by 22,684 biomass micro-generators in Northern Ireland. The RO in Great Britain does not include micro-generators which are supported under a separate FIT scheme.

addressed through the introduction of banded ROCs which allowed more ROCs to be issued for each MWh generated from preferred technologies and less for more mature technologies.

While these changes addressed immediate issues, the overall cost of the RO remained a concern. Because ROC prices were paid on top of electricity market revenues, because all renewable energy generation was covered, and because the ROC buy-out price did not adjust for changing technology costs, the scheme's costs were considered excessive, reaching £4.50 billion at the time of closure from £0.25 billion at the RO's start.[18] This led to the replacement of the RO with the current CfD mechanism, intended to improve the targeting of revenue support and so reduce its costs.

Total obligation calculation

Under the RO, the obligation in any one year is calculated six months in advance as the higher of:

- The target renewable energy share under the RO. Since 2015, this has been fixed at 0.154 ROCs per MWh generated.
- The expected number of ROCs to be issued from accredited capacity plus an 'uplift' of 10% to allow for forecasting errors.

For 2026/27, for example, the calculated obligation applying the target share is 41.0 million ROCs and applying the forecast issuance, with uplift, is 120.1 million ROCs. The obligation is, therefore, set at 120.1 million ROCs.[19]

This approach was adopted to ensure that, if ROC issuance was greater than the target renewable energy share, then the resulting excess supply doesn't lead to a collapse in ROC prices. However, it also means that the obligation volume is much higher than the target RE share and, as a consequence, customers are paying for 'excess' renewable energy generation.

Banding of ROCs

Banding was initially introduced in 2009 and adjusted a number of times, with the bands applied depending on the year in which capacity started generating. The final bands prior to RO closure are shown below. As an example of application, 1 MWh of generated by offshore wind earns 1.8 ROC but, if generated by onshore wind, only 0.9 ROC.

Table 4 Banded ROCs in the UK Renewables Obligation (post-2016, selected only)

Band	ROC issuance (ROC / MWh)
Energy from waste with CHP	1.0
Geothermal	1.8
Hydro	0.7
Landfill gas	0.0
Onshore wind	0.9
Offshore wind	1.8

18 As the buy-out price has continued to increase and existing capacity continues to be able to generate ROCs after its closure to new capacity, the total RO cost has also continued to rise. For 2023/24, the cost reached £6.75 billion.

19 Department for Energy Security and Net Zero. 2025. Calculating the Level of the Renewables Obligation for 2026 to 2027

Band	ROC issuance (ROC / MWh)
Offshore wind (floating turbines)	3.5
Solar PV (ground-mounted)	1.2
Tidal barrage / lagoon (<1 GW)	1.8
Wave	5.0

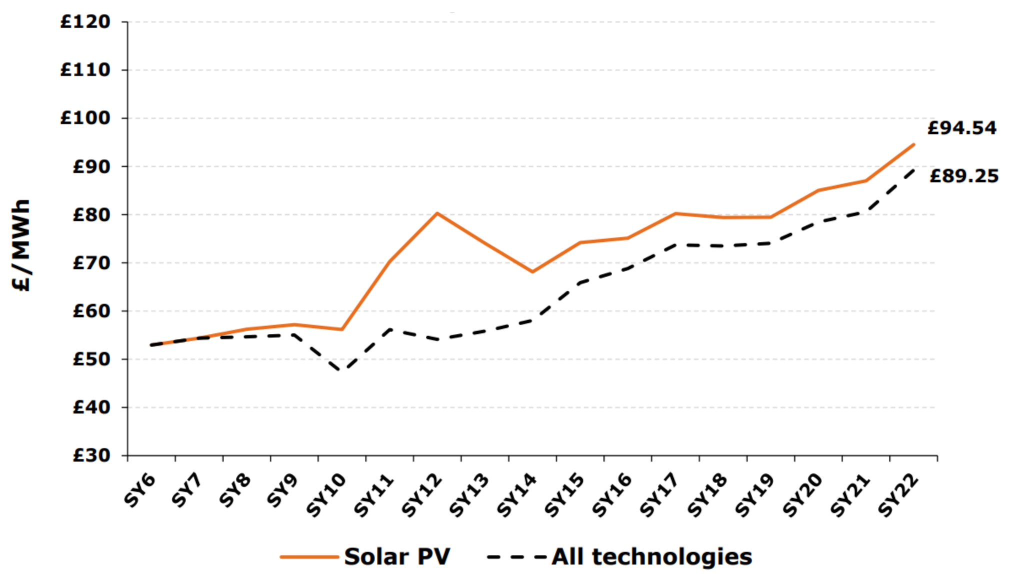
Notes: New biomass projects >1 MW are not eligible for ROC due to sustainability concerns

Source: Ofgem. 2025. Renewables Obligation Guidance: Generators

The use of banded ROCs can lead to significant differences between the shares of different technologies in renewable energy generation and in ROC issuance. In 2023/24, for example, offshore wind represented 19% of accredited capacity, 30% of generation from accredited capacity and 41% of ROC issuance. Meanwhile, onshore wind was 34% of generation but only 24% of ROC issuance.

While banded ROCs do support the development of favoured technologies, it does not address the issue of paying a premium (through the ROC) for technologies which do not necessarily need this to be competitive in the electricity market. Again, this may mean customers are paying in excess of costs for some technologies. For example, solar PV in 2023/24 was receiving a support payment of £94.54/MWh ($125.8/MWh) from the RO, on top of whatever it earnt from electricity market sales, well in excess of estimated large-scale solar PV costs of £46.5/MWh[20] (Figure 12).

Figure 12 Solar PV support prices under the UK Renewables Obligation



Source: Ofgem. 2025. Renewables Obligation Annual Report: Scheme Year 22 (1 April 2023 to 31 March 2024)

[20] Arup. 2025. Renewable Energy Generation Cost and Technical Assumptions – Onshore Wind and Solar PV. Report for DESNZ.

5.2.3 The CfD mechanism

The CfD mechanism has replaced the RO and is intended to reduce the overall costs of RE support. Key features of the mechanism are that:

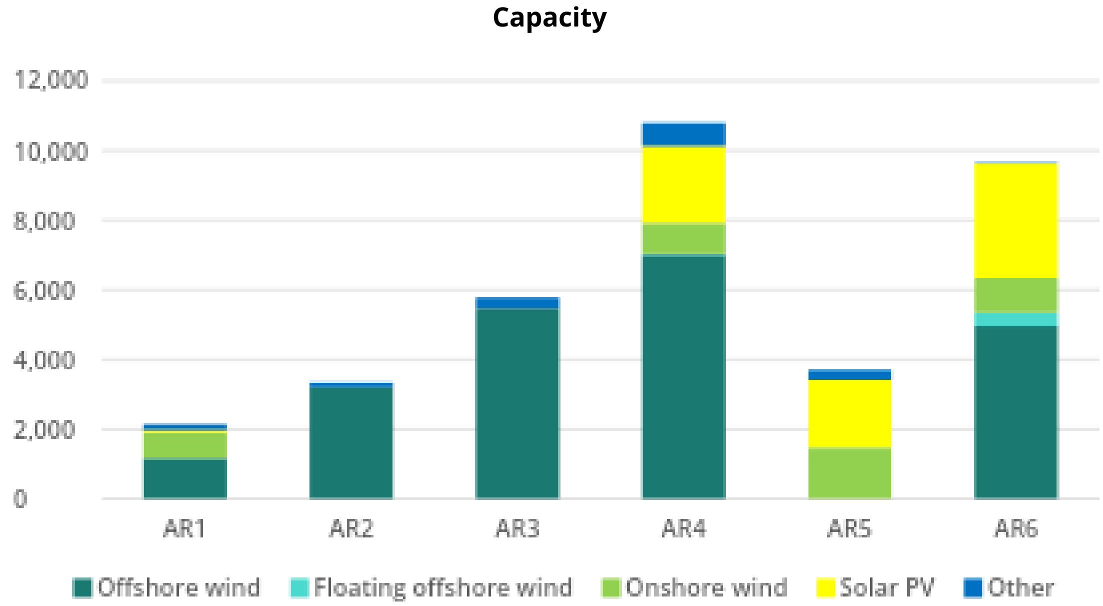
- Renewable energy capacity is procured through auctions (allocation rounds, AR). For each auction, the minister specifies the technologies to be procured, the target quotas for each, and the maximum budget for support under the mechanism.
- An administered price-cap is set in each auction, based on government estimates of the levelised costs of new capacity.
- Successful generators in the auction receive a 15-year CfD (extended to 20 years in the most recent auction). This uses the auction-clearing price as the strike price and the price on a reference power exchange as the market price.
- The CfD is signed with a government-owned and guaranteed corporation, the Low Carbon Contracts Company (LCCC).
- Generators are only paid under the CfD for energy generated. Therefore, they also need to participate directly in the electricity market, usually by signing a contract with a supplier who will then purchase their energy and will take responsibility for balancing their actual and contract volumes.
- Where the market price exceeds the strike price, the generator pays the difference to LCCC. Where it is less, LCCC pays the difference to the generator. LCCC recovers its costs or pays its revenues (if market prices exceed the strike price) from suppliers under a levy (universal charge) mechanism who pass these through to customers.

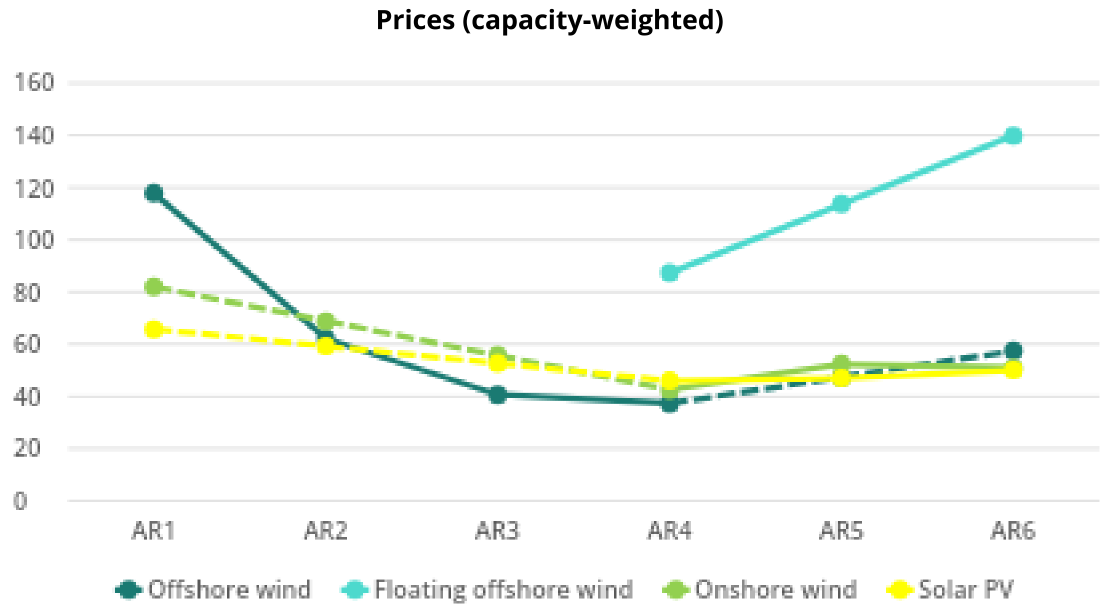
The CfD mechanism addresses the issues with the RO through the following routes:

- By limiting the mechanism to a subset of technologies, it only provides support to those technologies considered to require it.
- Capping the total quantities procured based on an allocated budget limits the amount that customers are expected to pay as financial support. This is further reinforced by the use of price-caps, based on estimated costs.
- Setting the support payment through an auction process ensures that renewable energy is procured at least-cost.
- Varying the premium paid based on the electricity market price removes the risk of "over-paying" when market prices exceed the costs of renewable energy generators.

To date, six allocation rounds have been completed. The seventh allocation round (AR7) was launched in August 2025 with awards expected in January 2026. The various allocation rounds have seen substantial volumes of capacity procured and, until AR5, falling prices. However, AR5 saw a failure to procure any offshore wind. This was attributed to price-caps being set at overly-optimistic levels, based on trends in previous AR, at a time when the costs of offshore wind were rising due to supply chain constraints, inflation, and a shift to more difficult sites. Higher price-caps were adopted for AR6 leading to a successful procurement round and have been further increased for AR7 (to £118/MWh compared to £81/MWh for AR6).

Figure 13 Great Britain CfD auction outcomes





Notes: Prices are reported at 2012 values for consistency. Current prices may be higher

Source: LCCC. Auction Outcomes (accessed 26 October 2025)

Rising costs have also led to projects being cancelled and, in some cases, rebid into later AR. For example, Orsted was originally allocated a CfD for its Hornsea 3 offshore wind project (2.9 GW) in 2022 under AR4. However, it then rebid part of this project (1.1 GW) into the later AR6 in 2024 and received a higher price.[21] Ofsted also announced in May 2025 the cancellation of the Hornsea 4 offshore wind project (2.4 GW), for which it was awarded a CfD in 2024 under AR6.

[21] The AR rules permit a reduction of the awarded capacity, freeing this up to be rebid in later AR.

These moves have been attributed to rising costs and the non-viability of the projects at the original prices.

5.3 Germany

5.3.1 Overview of the EEG mechanism

Germany's main mechanism for renewable energy support has been the Erneuerbare-Energien-Gesetz (EEG, Renewable Energy Sources Act). The EEG was first enacted in 2000 and has been through a series of amendments in 2004, 2009, 2012, 2014, 2017, 2021, and 2023. The EEG was preceded by the Stromeinspeisungsgesetz (StrEG, Electricity Feed-In Act) of 1991 which established the initial FIT regime for renewable energy.

From 2000 to 2017, the basic structure of renewable energy support remained unchanged, although the details were continually amended. The structure adopted was:

- Renewable energy targets were specified by law.
- FITs were set by technology and also specified by law, meaning reductions (or increases) require new primary legislation. Eligible generators receive a 20-year contract at the specified FIT.
- Degression pathways (preset reductions in FITs) were specified. Initially, these were set in primary legislation, but later amendments allowed them to be revised without the need for a new law.
- Quotas were established for technologies, to help manage the total cost of the support scheme. These were revised to be flexible with more recent amendments accelerating degression of FITs if installed capacity exceeded quotas, rather than making these a firm cap.

There were continual concerns that solar PV, in particular, was receiving excessively high tariffs relative to its costs leading to an ongoing process of reducing these through successive amendments.

The 2014 and 2017 amendments to the EEG introduced major changes to the support mechanism. The basis for support was switched in 2014 from a fixed FIT to a premium on electricity market prices (so that renewable energy generators receive the difference between their FIT and the electricity market price). To receive the premium, renewable energy generators must sell their electricity through a power exchange.

Technology-based auctions for FITs were introduced in 2017 for larger installations using more mature technologies (solar PV and onshore wind exceeding 750 kW, biomass exceeding 150 kW, and offshore wind). Smaller installations and other technologies continue to receive a fixed FIT.

Unlike the CfD model in Great Britain, the premium paid under the German EEG mechanism is one-way. Where the market price is less than the support price for the renewable energy generator, as determined through auction, then the generator receives the difference as in Great Britain. However, where the market price is higher than the support price, the generator receives the market price with no requirement to pay back the difference. Instead, the generator is assumed to factor such instances where it earns a market price above its cost into its auction bids. This should lead to a lower requirement for support payments.

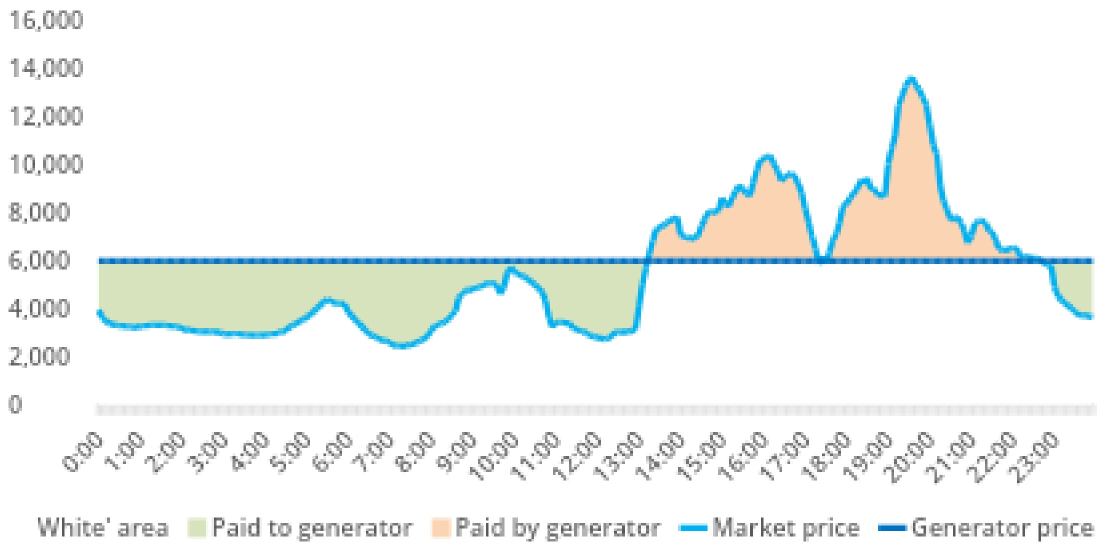
The German EEG mechanism also pays no premium where the market price is negative for a given number of hours per day (a number which has been reduced over successive amendments). A negative market price is taken to indicate excess supply and, therefore, further generation is not required. Without this provision, renewable energy generators under the support scheme have an incentive to sell energy, even at negative prices, as they would be compensated through the market premium under the support mechanism for the resulting losses in the electricity market.

The differences between the two mechanisms are illustrated below.

Figure 14 Different market premia mechanisms illustrated

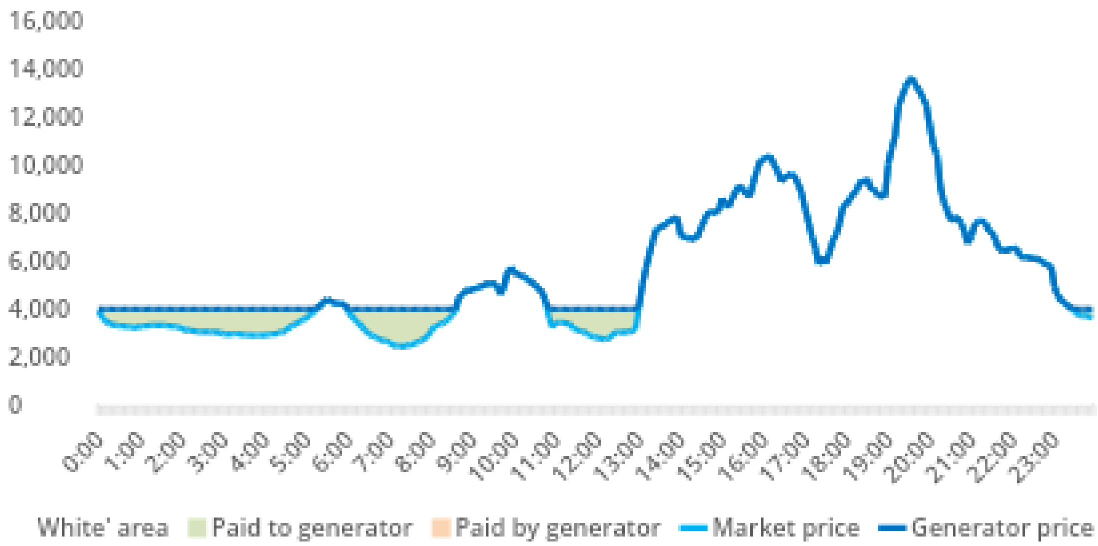
Two-way premium (Great Britain CfD)

The generator receives or pays the difference between the market price and the contract price, so that the price to the generator is constant.



One-way premium (Germany EEG)

The generator receives the higher of the market price and the contract price. The additional upside this offers to the generator is reflected in a lower required contract price than with a two-way premium.



Source: Illustrative example

5.3.2 Issues with the EEG mechanism

The costs of renewable energy support under the EEG have been a continual source of concern. These concerns have driven the shift from a FIT towards the use of a premium combined with quotas and auctions. From 2022, the government has moved the costs of renewable energy support schemes from electricity bills to general taxation and the proceeds of auctions of allowances under the European Union's Emissions Trading Scheme. While this does not reduce the costs, it does make them less visible and helps intensive electricity users.

The high costs are, to a large extent, due to a wave of rooftop solar installations between 2008 and 2012 under high FITs. These are estimated to represent 49% of total EEG payments.[22] This has similarities to Great Britain where the high costs of renewable energy support schemes reflect past decisions rather than current mechanisms, which have been reformed to emphasise cost-efficiency.

Further reforms are planned to reduce costs. These include ending FITs for smaller installations, fully eliminating premium payments during negative pricing periods, and the possible introduction of a CfD mechanism to recover any excess of market prices over the contract price for renewable energy generators.[23]

5.4 Australia

5.4.1 Overview of the Capacity Investment Scheme

The Capacity Investment Scheme (CIS) was introduced in 2023. The CIS is intended to provide greater revenue certainty for renewable energy generators, making them easier to finance.

Under the CIS, auctions are held to procure qualifying capacity. Successful bidders are awarded a contract for up to 15 years with a floor and ceiling revenue. Where actual revenues from the electricity market fall below the floor, a top-up payment covering 90% of the difference is made and, where they exceed the ceiling, part of the excess is returned. This creates more market exposure for the generator than under the British and German models. Consequently, it also means the generator has stronger incentives for efficient dispatching (ie, where market prices exceed its variable costs), while still protecting the generator against extremely high or low market prices.

Total capacity to be procured under the CIS was set at 32 GW in November 2023, comprising 23 GW of variable renewable energy capacity (wind and solar) and 9 GW of dispatchable capacity (including storage). In July 2025, these targets were raised to 26 GW and 14 GW respectively. The CIS is a national-level scheme. It is linked to state-level targets and mechanisms by allocating target procurements under the CIS between states based on negotiations as to individual states' levels of ambition for renewable energy expansion.

The first full CIS tender was held in December 2024, following two smaller pilot auctions, with four tenders having been held to date (two for variable generation in the National Electricity Market, NEM, one for dispatchable capacity in the NEM, and one for dispatchable capacity in the Wholesale Electricity Market, WEM, in Western Australia). The results are summarised below. Tenders have been dominated by BESS capacity. Requirements and evaluation criteria can differ from round to round, to allow more flexibility to adjust to needs.

22 Montel Energy. 2025. Future of German EEG subsidies: is the system still sustainable?

23 Alkousaa R. 15 September 2025. " Germany to scrap fixed tariffs for new renewables, pivot to market support ". Reuters

Table 5 CIS tender results

Tender round	Type	Awarded projects	Capacity procured
New South Wales pilot *November 2023*	Dispatchable	3 x BESS 3 x virtual power plants	1,075 MW storage 2,790 MWh storage
South Australia – Victoria pilot September 2024	Dispatchable	6 x BESS	995 MW storage 3,626 MWh storage
1: National Electricity Market December 2024	Generation	5 x solar 6 x wind 7 x solar + BESS 1 x wind + BESS	6,375 MW VRE 1,151 MW storage 3,562 MWh storage
2: Wholesale Electricity Market March 2025	Dispatchable	2 x solar + BESS 2 x BESS	654 MW storage 2,595 MWh storage
3: National Electricity Market September 2025	Dispatchable	16 x BESS	4,130 MW storage 15,370 MWh storage
4: National Electricity Market October 2025	Generation	1 x solar 7 x wind 11 x solar + BESS 1 x wind + BESS	6,640 MW VRE 3,509 MW storage 11,444 MWh storage

Source: Department of Climate Change, Energy, the Environment and Water. Closed CIS Tenders (Accessed 26 October 2025)

5.4.2 Issues with the Capacity Investment Scheme

As a new mechanism, experience with the CIS is limited. However, recent commentary has identified a few possible concerns:[24]

- The effect of the CIS is to reduce the "pool" of renewable energy capacity available to corporate buyers, as generators prefer longer-term and more credit-worthy contracts from the CIS. This makes it harder for corporates to hedge against market price risks.
- This process also leads to ever-increasing government involvement in planning new generation investment, as government tenders drive decisions on technologies and locations. This may lead to inefficient and higher-cost investment decisions.
- CIS tender rounds have been oversubscribed. This has led to worries that project developers are bidding unrealistically low prices to be awarded contracts, in the hopes these can be renegotiated at a later date.

These concerns are, of course, not unique to Australia. However, the CIS does represent a fundamental shift away from previous approaches reliant on market-driven investment, unlike Great Britain and Germany where renewable energy support schemes have been an integral part of market design for decades.

[24] This discussion draws on: Lee D. 2025. " Are CIS-ters doin' it for themselves? Part 2: Understanding why there are delivery challenges ". WattClarity

6 Key findings

6.1 Summary

The international trend, as illustrated by the examples of Great Britain, Germany, and Australia, is away from universal support payments to all renewable energy generators and from the use of fixed support payments, and towards mechanisms typified by:

- The use of market-based support mechanisms, with premium payments to offset the difference between market and contract prices.
- Procurement of renewable energy under support schemes through centralised, technology-specific, auctions.

This move has been driven by concerns over the rising costs of support schemes. The shift is expected to reduce these costs by only paying for those technologies that require support, and by not “over-paying” where, for example, the market price already exceeds the cost of the renewable energy technology.

In the Philippines, the trend could be seen as being in the other direction. The GEAP mechanism represents, in effect, a technology-specific auction with the equivalent of a two-way premium contract to adjust for differences between market and contract prices. However, in the longer-term, the intention is to substitute this with the RPS and accompanying REM, built around the use of universal support payments at a fixed rate through the requirement to purchase RECs.

This appears to open up two main options for the Philippines moving forward to enhance its support mechanisms:

- **Retain the GEAP** as the primary support mechanism, in line with international practice, but with reforms to improve its functioning.
- **Continue to fully transition to the RPS and REM** but doing so while drawing on the lessons from international experience (notably Great Britain) as to cost containment.

6.2 Retaining and reforming the GEAP

The first option is to retain the GEAP but to reform its functioning. Previous UNOPS ETP reports have already highlighted key areas for such reform (as discussed in Section 4.3.2), and these are reinforced by the experience of technology-specific market-based mechanisms elsewhere. The reform areas include:

- **Limiting the auction** to those technologies which are not viable at current market prices, to avoid paying for RE generators which can recover their costs from energy sales through the WESM and PSAs alone.
- **Increasing the price-caps** applied to different technologies, to ensure these are better aligned with the costs of new generation. For example, auctions (AR) in Great Britain are preceded each time by a review of the applicable administrative strike prices (in effect, price-caps) to incorporate recent evidence.[25] This does not prevent these caps being set too low (as the AR5 results showed) but does allow for rapid correction (as the following successful AR6 demonstrated).

[25] See, for example: Department for Energy Security and Net Zero. 2023. Methodology used to set Administrative Strike Prices for CfD Allocation Round 6

- **Conducting more frequent auctions**, ideally on a regular cycle, to assist investors in managing the project development and delivery cycle and to enable them to maintain the necessary management teams and supply chains in place without long gaps between auctions. While Great Britain's auctions remain somewhat irregular, they have broadly followed a pattern of one per year.
- **Allowing more flexibility as to commissioning dates** for capacity to allow successful bidders to adjust for project circumstances, rather than being forced to cancel projects. More recent GEAP auctions have adopted longer lead-times and the ability to select commissioning years. Further flexibility could be introduced by, for example, adopting the mechanism for rebidding part of contracted capacity in later auctions, as in Great Britain.
- **Make the REPA a "bankable" contract** by addressing gaps and improving protection for investors, following the examples of contracts in other support mechanisms. This could include making this an explicit CfD rather than, as now, an implicit one.
- **Moving to a pay-as-clear pricing model** in place of the current pay-as-bid model, following the example of other similar auctions internationally. While this may appear to increase costs, as it implies some generators receive contract prices exceeding their own costs, other auctions have favoured this as increasing competition and as reducing the risk of bidding errors (where a participant bids higher than their cost based on expectations of the bids from other participants or where a participant misestimates costs and bids a price below the viable level).

Going further, it may be worth considering whether **moving to a one-way premium or a revenue cap and floor mechanism**, as in Germany and Australia respectively, is desirable. These both transfer some market price risk to generators, in the expectation that the higher upside potential will reduce the required contract price in the support mechanism. The great exposure to market risk also creates stronger incentives on the generator to ensure it is dispatched efficiently in the WESM (eg, during high-priced periods).

However, it is important to recognise that this does not reduce the total costs of the generator or the total payments it receives (the sum of market and support revenues). Indeed, it is possible that the higher market risk under these mechanisms is reflected in a higher cost of capital which pushes up costs and required prices.[26]

6.3 Fully transitioning to the RPS and REM with cost containment measures

The second option is to continue the transition to reliance on the RPS and REM to support renewable energy generation, but to revise the cost containment measures. Currently, costs are managed by the combination of a phased increase of RPS targets, setting relatively low price-caps on RECs traded in the REM, and low levels of penalties for non-compliance. However, this combination has resulted in extremely low REC prices which are unlikely to be sufficient to make new renewable energy technologies viable.

The challenge, then, is how to increase REC prices to levels that can finance investment in renewable energy while avoiding this leading to excessive support costs to be paid by customers. The British experience suggests that this might be best done by introducing some form of

[26] Evidence on the relationship between electricity market price risk and the cost of capital is sparse. Estimates at the time of introducing the CfD mechanism in Great Britain were that the reduced price risk would lower the cost of capital for onshore wind by 0.85-1.70 percentage points and for offshore wind by 0.00-0.90 percentage points, which provides a possible indication of the impacts of reducing risk exposure. (NERA. 2013. Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime. Report for Department of Energy and Climate Change)

technology segmentation so that payments to technologies reflect their needs for support while, at the same time, allowing REC prices to rise.

For example, revisions to the RPS and REM mechanism could include:

- **Introducing a buy-out requirement for REC shortfalls** using an administered buy-out price, as in the British RO, with the buy-out price being set sufficiently high to create strong incentives for suppliers and DUs to procure RECs.
- **Linking the REM price-cap to the REC buy-out price**, plus a margin to allow for the potential recycling of buy-out revenues to suppliers and DUs (if this is permitted).
- **Setting the RPS target in each year taking into account the volume of RECs being issued**, as in the British RO calculation of annual obligations, to avoid the risk of excess RECs pushing prices down to ineffective levels.
- **Adopting technology banding for REC issuance**, as in the British RO, to reduce support payments to mature technologies that are already competitive and, thereby, to provide "space" for increases in support payments for technologies that are currently less viable.

As an illustration of how banding might operate, the current REC price cap for all technologies is set at 241.56 PHP/kWh. Applying the same assumptions on costs of individual technologies (obtained from recent PSAs) and the market price (represented by GWAP), the required support by technology and how this might be converted into technology banded REC issuance is presented below.

This example assumes a continued price-cap of 241.56 PHP/kWh so that, for example, a wind generator needs to earn 8.4 RECs per MWh of electricity generated to cover its required support level of 2,027.3 PHP/kWh. A higher REC price-cap would imply that fewer RECs would need to be issued per MWh to deliver the same level of support. Note that this example, based on the values used in the REC price-cap calculation, shows solar and wind as requiring support. This contrasts with the evidence shown earlier that solar, in particular, is already able to cover its costs from energy sales in the WESM and does not require additional revenues. This does suggest that the price-cap calculation may need to be reviewed and updated.

In this example, a zero REC value is shown where market prices exceed the RE technology's cost, and so no additional revenues are required from REC sales. This may, of course, not be feasible if the RPS is retained in its current form as it may then mean mandated participants cannot obtain sufficient RECs to meet their obligations. This does serve to demonstrate one of the possible risks of the RPS approach—that participants need to pay for RECs to meet the RPS, even where the technologies concerned do not need that extra revenue to be viable.

If banding is introduced, the REC bands should be updated at intervals to reflect changes in both technology costs and market prices. For example, a review might be conducted at three to five-year intervals. Updated bands would only apply to generators commissioning after the new bands became effective. Older generators would continue to apply the bands in effect at the time of their commissioning, reflecting their expectations at the time the investment was made.

Table 6 Illustrative banding of REC issuance (ERC Resolution No. 08 of 2024)

1 REC = 1 MWh of renewable energy generation

REC price-cap = 241.56 PHP/kWh (used as the value of 1 REC)

Technology	Current		Banding	
	Support rate (PHP/kWh) *GWAP less capacity-weighted average of PSA prices*	RECs per MWh *Uniform*	Support rate (PHP/kWh) *GWAP less technology-specific PSA price*	RECs per MWh *Technology-specific with minimum of zero*
Biomass	241.56	1.0	(2,713.9)	0.0
Geothermal	241.56	1.0	(1,359.5)	0.0
Impounding hydro	241.56	1.0	(1,842.3)	0.0
ROR hydro	241.56	1.0	(1,031.0)	0.0
Solar	241.56	1.0	657.2	2.7
Wind	241.56	1.0	2,027.3	8.4

Notes: Negative values are shown as (). Banded RECs are rounded to the nearest 0.1. The price data used shows a PSA price for solar in excess of WESM prices, although other evidence suggests that solar PV is already competitive in the WESM (see earlier discussions in this report)

Source: Calculations using price data from [ERC Resolution No. 08 Series of 2024]

The cost implications for customers of such a change are ambiguous, depending on the split of REC issuance between technologies. If most RECs come from wind and solar then, using the bands in Table 6, this is likely to increase total support costs. If most RECs come from geothermal and hydro, then it is likely to reduce them.

6.4 Implications for the WESM

Both of the potential sets of reforms set out above would have the effect of restricting payments for environmental characteristics (via the GEAP or RECs) to RE generators which are not viable at current WESM prices. Those technologies which are already viable would not receive further payments on top of their revenues from energy sales.

There are two potential implications for the WESM:

- Currently, RE generators can still earn a positive revenue even at negative WESM prices due to the top-up revenues received from GEAP or sale of RECs. If they no longer receive these top-up revenues, they will be reluctant to submit negative price offers as, if accepted, this would lead to them losing money when generating. This may reduce the incidence of negative WESM prices and push up energy prices to customers (although impacts will likely be small and offset by the lower GEAP and/or REC payments).

- RE generators who lose the ability to mitigate market price risk through long-term contracts signed under GEAP will look to replace these by signing PSAs with DUs and suppliers. This will potentially increase the share of generation covered by PSAs and reduce liquidity in the spot market.