REPORT

Enhancing the Spot Market to Attract Investments to Renewables

Deliverable 4: WESM Price Mitigation Revenue Impacts (Final Report)

4 December 2025

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Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
BIOF	Biofuels
CCGT	Combined Cycle Gas Turbine
CPT	Cumulative Price Threshold
DOE	Department of Energy
ECA	Economic Consulting Associates
ERC	Energy Regulatory Commission
FIT	Feed-in Tariff
FOM	Fixed Operating and Maintenance Costs
GDP	Gross Domestic Product
GEO	Geothermal
GWAP	Generator-weighted Average Price
HYD	Hydro
IEMOP	Independent Electricity Market Operator of the Philippines
IES	Intelligent Energy Systems
LCOE	Levelized Cost of Electricity
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
MPF	Market Price Floor
NATG	Natural Gas
NCL	Nel Consulting Limited
NEM	Australian National Electricity Market
NREL	National Renewable Energy Laboratory
NREP	National Renewable Energy Program
OCGT	Open Cycle Gas Turbine
PC	Price Cap
PEMC	Philippine Electricity Market Corporation
PEP	Philippine Energy Plan
PHES	Pumped Hydro Energy Storage
PHP	Philippine Peso
PJM	Pennsylvania-New Jersey-Maryland
PPC	Primary Price Cap
PSH	Pumped Storage Hydro
SPC	Secondary Price Cap
SRMC	Short-run Marginal Cost
UNOPS-ETP	Energy Transition Partnership
VOM	Variable Operating & Maintenance Cost
VRE	Variable Renewable Energy
WESM	Philippines Wholesale Electricity Spot Market

Definition of Terms

Backcasting – in the purposes of this report**,** refers to the process initially done to ensure that the model database is calibrated against historical pricing and generation outcomes, improving the accuracy and credibility of projections presented herein.

Energy-only Market – an electricity market where energy is the sole commodity traded, excluding ancillary services.

Generator Weighted Average Price (GWAP) – in the context of WESM, refers to the time-weighted average of generator nodal energy prices.

Indexed – refers to the any quantity being adjusted using a benchmark indicator as reference.

Locational Marginal Price (LMP) – in the context of WESM, refers to the price of supplying electricity determined each period for specified node or location in the power system to reflect the cost of transmission line loss or congestion.

Loss of Load Expectation (LOLE) – metric, expressed in units of time, used to quantify the likelihood of the power system's inability to meet demand in a specified period.

Primary Price Cap (PPC) – in the current context of the WESM, refers to the maximum price, expressed in Php/MWh, that a generator can offer.

Reliability – the ability of the power system to adequately and consistently meet the electricity demand.

Supply Margin – refers to the amount of available supply against the peak load in the market.

Secondary Price Cap – a price mitigation measure to safeguard consumers against sustained high prices. In the current WESM, it amounts to 6,245 Php/MWh and is applied to trading intervals whenever the rolling average of the generator weighted-average prices for the past 72 hours reaches the set cumulative price threshold. The secondary price cap remains in place until the rolling average goes below the threshold.

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1 Executive Summary

This report corresponds to “Deliverable 4: Updated Price Mitigation Measures” of the project and outlines recommendations for suitable price mitigation measures aimed at enhancing market efficiency and competition, preventing excessively high or low prices, and fostering investment in power generation. The proposed mechanism changes are informed by detailed Wholesale Electricity Spot Market simulations.

Reforms to the WESM price caps should aim to encourage efficient investment in future generation needs while considering the commercial outcomes for existing generation investments in the context of regulatory stability. This report covers recommendations for an appropriate price mitigation measure for the Philippines WESM, supported by modelling and analysis. It also reflects the feedback from consultations and clearly sets out the proposed values for the Primary Price Cap (PPC), Market Price Floor (MPF), and Secondary Price Cap (SPC), or an alternative formulation, where appropriate.

As the cost structure of the WESM evolves with higher renewable energy (RE) generation targets, increased volatility is anticipated due to the rising share of intermittent generation resources. This shift underscores the growing need for peaking or firming generation options. The modelling and analysis conducted in this report supports a review of the current methodology for setting price caps and updating their values in alignment with promoting the WESM's future supply outlook.

The options for price mitigation measures have been informed by the analysis in Deliverable 3. The three scenarios proposed are discussed below:

- **Scenario 1:** Status Quo – no changes to the PPC, MPF, and SPC. This is essentially the Base or reference case against which the performances of other options can be assessed.
- **Scenario 2:** Alternative parameterisations of PPC, MPF, and SPC. This scenario specifically models the proposed amendment to the secondary price cap based on an indexed administered price cap and extending the threshold upon which the secondary price cap triggers. The analysis in Deliverable 3 suggested current SPC levels were triggered too frequently, potentially stifling necessary price signals for new entrant investment.
- **Scenario 3:** Optimal parameterisations of price mitigation measures. This scenario specifically explores what the optimal PPC needs to be, assuming the amended SPC from Scenario 2 is included, to ensure revenue adequacy across all generation types that are likely needed over the forecast horizon. It may also be influenced by adjustments that would be more suited to modern technology mixes—e.g., as characterised by hybrid systems (variable renewable energy plant + energy storage) and energy storage in general. For example, primary price caps that consider storage duration.

Modelling results and analysis

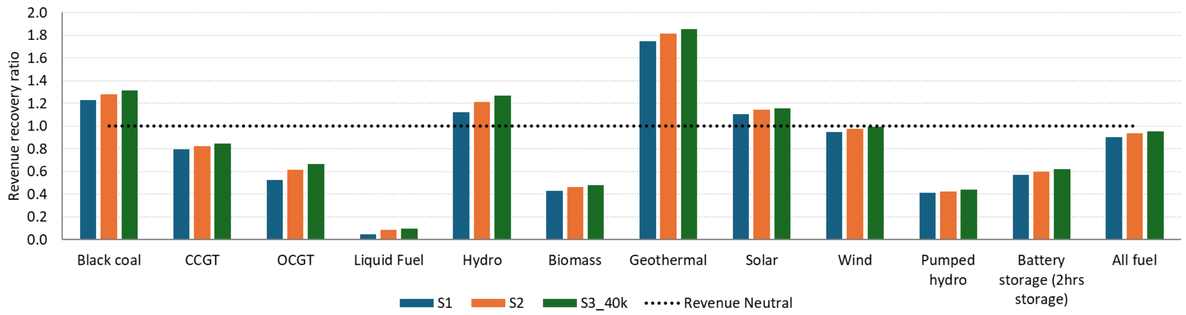
The analysis from the modelling simulation of the WESM under different price settings explores the impact of price caps on revenue adequacy and generator viability across three scenarios, combining historical calibration with forward-looking modelling to assess cost recovery for existing and new entrant generators.

The backcasting process provides a robust foundation by ensuring the model aligns with historical outcomes, enhancing credibility and accuracy. Regional energy prices capped at Php 32,000/MWh closely match historical price duration curves at lower price levels, while deviations—such as annual modelled prices being 8% and 15% lower than actuals for Luzon and Visayas, respectively, and 7% higher for Mindanao—highlight the cautious baseline adopted to avoid overestimating generator revenues. This calibration strengthens the reliability of forward projections and ensures that the insights derived from Scenarios 1, 2, and 3 are grounded in realistic market dynamics.

Scenario 1 establishes the baseline by assessing the current PPC and SPC settings, revealing frequent SPC active intervals and suppressed price signals that result in revenue shortfalls for peaking plants and flexible generators. Scenario 2 introduces an amended SPC that raises the price threshold, significantly reducing the frequency of active SPC intervals (from 4.5% in Scenario 1 to 0.4%) and improving cost recovery opportunities for most technologies. However, despite these improvements, several technologies—such as open cycle gas turbines (OCGTs), BESS, and pumped hydro—remain revenue inadequate under the amended SPC, necessitating further adjustments.

Scenario 3 builds upon these findings by retaining the amended SPC but increasing the PPC to Php 40,000/MWh. This adjustment generates stronger price signals, enabling technologies with persistent revenue shortfalls to recover costs more effectively. The system-wide revenue adequacy ratio improves to 0.9544 in Scenario 3, reducing the revenue gap to within a 5% range of sufficiency—a significant improvement over the shortfalls of 9.9% and 6.5% observed in Scenarios 1 and 2, respectively.

Figure 1 **Cost Recovery for New entrants at system level over 2025-2030**



While hydro and geothermal consistently achieve cost recovery, and solar and wind remain viable despite intermittency, peaking technologies such as OCGTs, BESS, and pumped hydro continue to rely on higher price caps to address revenue shortfalls. The results from Scenario 3 demonstrate that the proposed PPC effectively enhances revenue adequacy without introducing inefficiencies, and addressing the challenges identified in earlier scenarios.

With current contracting profiles, batteries, pumped hydro, and wind generators offer their entire capacities in the spot market, while solar plants continue to derive a low proportion of their revenues from contracts due to their intermittent nature. This highlights the dependence of these technologies on spot market dynamics for revenue generation. Scenario 3 achieves a balanced spot revenue increase for VRE, peaking gas plants, and storage systems, with solar and wind seeing an average increase of 6%, batteries with 25%, pumped hydro with 3%, and at least 11% for peaking plants throughout the forecast horizon. Furthermore, this underscores both the reliance of these generators on higher price caps to recover costs and the importance of firming generator technologies with increasing VRE generation.

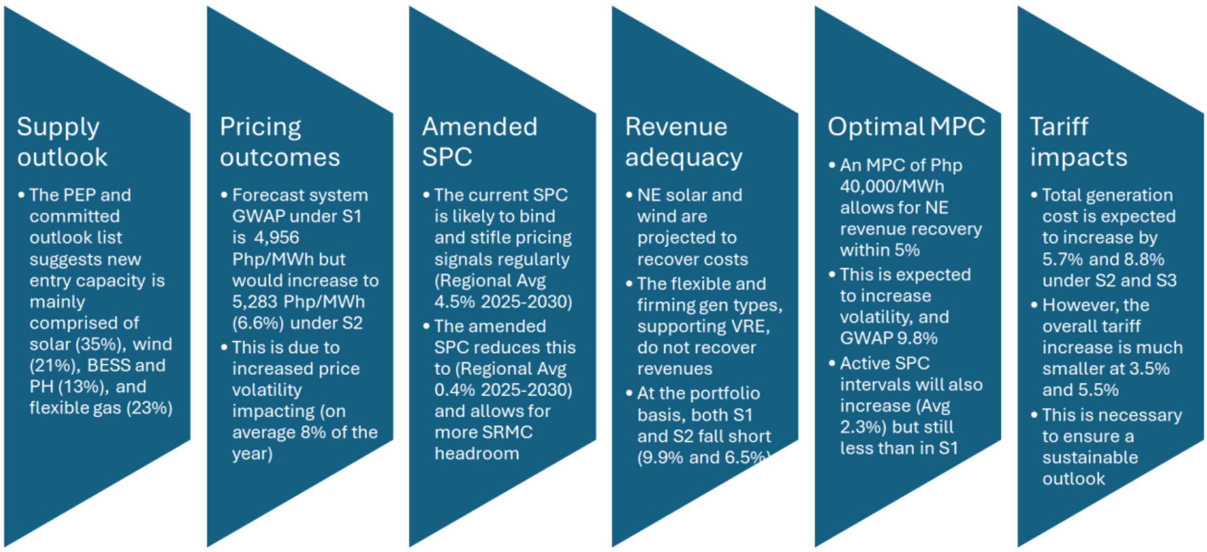
Setting the PPC at the optimal level of 40,000 Php/MWh in Scenario 3 results to 8.8% increase to the generation cost tariff component compared to the base scenario. The overall tariff impact is limited to an increase of 5.5%. Moreover, the economic cost of unserved energy should be included in any end-user cost assessment. The analysis shows that the higher tariff-cost under Scenario 3 is more than offset by the reduction in unserved energy costs relative to Scenario 1 and 2. This illustrates the overarching trade-off that must be considered in power system planning: the cost of additional investment in the power system versus the level of reliability that is desired or appropriate for the WESM. The configured price settings in Scenario 3 allow new entrants to recover costs, thereby encouraging the target renewable energy mix while maintaining reliable, sustainable, and affordable electricity in the long run.

These findings underscore the critical role of calibrated price caps in improving cost recovery, ensuring stability, and incentivising investment. Scenario 3 offers a balanced and effective framework for achieving these objectives, ensuring the financial sustainability of both existing and new entrant generators while facilitating the transition to a cleaner and more adaptable energy mix.

Key Findings

The modelling analysis highlights critical findings on supply dynamics, pricing behaviour, revenue recovery, and tariff impacts, underscoring how adjustments to the SPC and PPC influence the energy market's performance and sustainability.

Figure 2 Critical findings and implications of changed price settings



2 Introduction

2.1 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 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 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 Operator of the Philippines (IEMOP) to monitor and analyse market and price trends, and update price mitigating measures in the future.

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

The Southeast Asia Energy Transition Partnership (ETP) unites philanthropies 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:

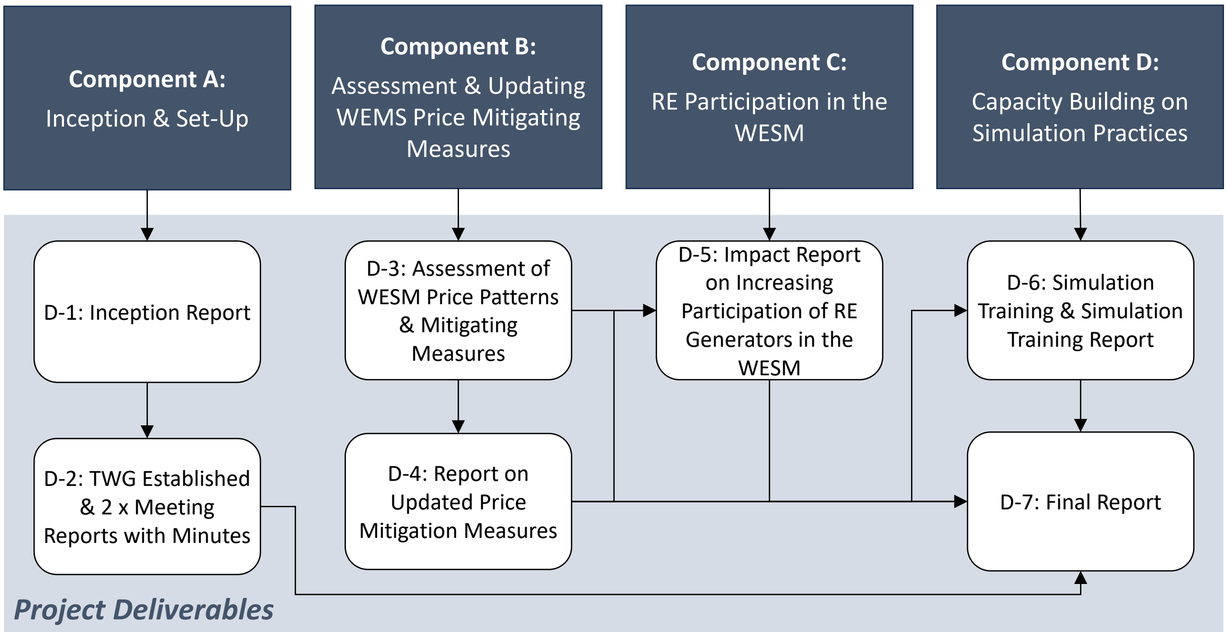
- Aligning policies with climate commitments,
- Reducing the risk associated with investments in renewable energy and energy efficiency,
- Expanding smart grids, and
- Expanding knowledge and awareness building.

2.3 Scope of Work

The project will address 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 Figure 3.

Figure 3 Components and Deliverables



This report corresponds to Deliverable 4 and outlines recommendations for suitable price mitigation measures aimed at enhancing market efficiency and competition, preventing excessively high or low prices, and fostering investment in power generation. The proposed mechanism changes are informed by detailed WESM market simulations.

The report covers recommendations for an appropriate price mitigation measure for the Philippines WESM, supported by modelling and analysis. It also reflects the feedback from consultations and clearly sets out the proposed values for the PPC, MPF and SPC, or an alternative formulation, where appropriate.

2.4 Report Structure

This report corresponds to the Deliverable 4 of the project and is structured as follows:

- Section 3 provides a background covering a summary of the assessment of WESM Price trends preceding the study in this report;

- Section 4 provides a summary of the approach and base scenarios considered for WESM modelling;
- Section 5 details the major assumptions behind the WESM simulation modelling;
- Section 6 presents the modelling results of the WESM simulations of scenarios under different price setting options;
- Section 7 highlights the key findings of the simulation modelling and implications of the amended SPC and proposed PPC.

The basis of figures quoted in this report, unless otherwise stated, is listed in Table 1.

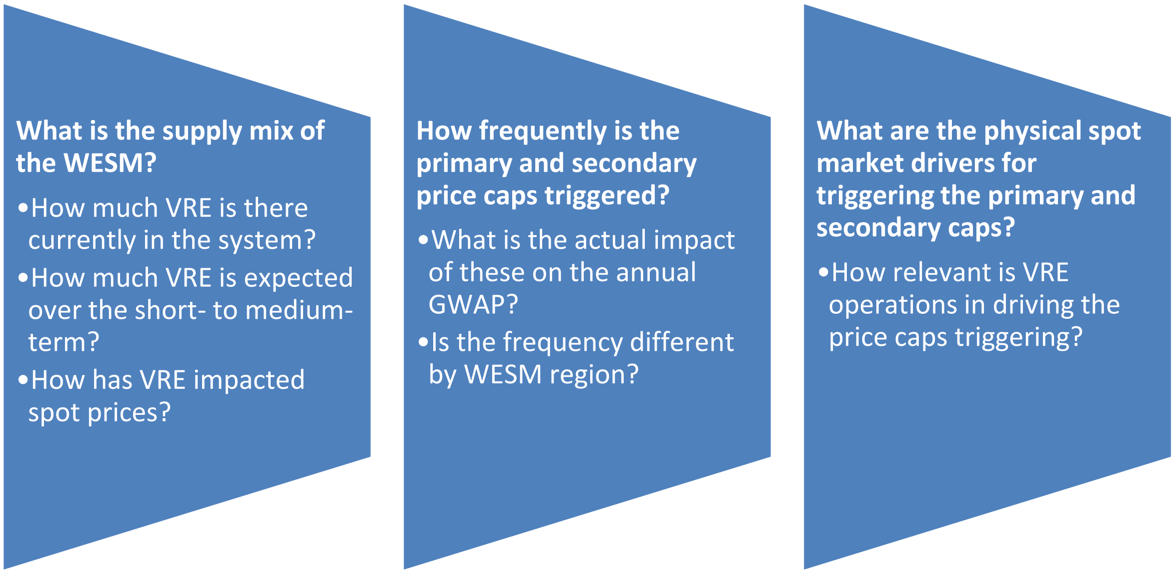
Table 1 Reporting basis

Reference	Basis
Capacity and generation	As generated
Demand	Operational, sent out basis
Currency and basis	Real 2023 Php
Average prices	Time-weighted
Year	Calendar year basis, Jan to Dec

3 Background

The preceding report (Deliverable 3: Assessment of WESM Price Trends) focused on analysing WESM price trends, examining historical volatility levels, the frequency of primary and secondary price cap triggers, and the physical spot market factors contributing to volatility. Understanding the relationship between the increasing penetration of renewable energy and market price volatility is crucial for developing policies that encourage investments in renewable energy. Figure 4 highlights the key questions addressed in the analysis.

Figure 4 Analysis of WESM Price Trends



The Philippine Wholesale Electricity Spot Market has greatly evolved since it began its commercial operations in 2006. Due to the sustained high prices in the past, policies including Offer Price Caps, Offer Price Floor, and Secondary Price Cap have been put in place to control prices while setting a competitive environment among the market participants. These price settings and other WESM rules ensure generator revenue adequacy, promote efficient investment, and minimise end-user costs, which are the core objectives of the WESM. The Primary Price Cap (PPC) only applies to the generator offers which results to the market prices exceeding the set price cap. In contrast, the Secondary Price Cap (SPC) is applied to the final market prices, directly influencing the market outcomes. These price settings were derived from the operational costs, capital expenditures, and investment costs at the time they were implemented. The level of the primary price cap still imposed in the present market and has not been adjusted since 2015.

The key findings from Deliverable 3 informing the modelling approach is summarised below.

International Review of Price Mitigation Measures

- There is currently no quantitative measure of reliability in place. An explicit reliability standard should be established, which will, in turn, guide the setting of overall price cap levels. A formal comprehensive rule change to introduce a reliability framework and the setting of price caps could take up to several years.

- The WESM lacks a robust framework comparable to that in the Australian NEM which clearly sets out principles and processes for setting price caps in relation to reliability standards and generation investment.
- The existing price cap settings have been based on a traditional energy mix and have not been updated to support the ongoing energy transition within the WESM.
- Unlike other markets, the WESM applies caps and floors only to bids, rather than to final energy and reserve prices.

WESM Price Trends

- Price settings should be designed to support the increased presence of variable renewable energy (VRE) in the WESM outlook.
- The frequency of triggering the Primary Price Cap (PPC) is high, and prices can substantially exceed 32,000 Php/MWh. Similarly, the frequency of triggering the Secondary Price Cap (SPC) has increased significantly due to the reduction of the Cumulative Price Threshold (CPT) period to three (3) days. This situation may potentially discourage investment in generation particularly those with high fixed costs, as the current SPC sets the market prices but has not been updated to align with the current economic conditions.
- The secondary price cap imposition is mainly influenced by the high demand, high outages, and high generator offers over the past 10 years. Intervals associated to the SPC have had higher contributions on the annual average GWAP since the transition of the WESM to a 5-minute market. This is not only due to the reduced rolling average period, but also because of the high prices that tend to manifest due the intermittent imposition while there are sustained high prices brought by prevailing market conditions such as high demand and high outages.
- While the market price floor does not require revision at this time, conditions should be closely monitored as VRE penetration grows. The impact of high prices driven by low renewable energy generation is expected to rise with increasing VRE penetration. Therefore, price caps should also incentivise investment in firming generation technologies, such as battery energy storage systems (BESS), peaking gas plants, and pumped storage.

Price Mitigation Revenue Impacts

- Potential revenue losses from capping settlement prices to the price cap would likely be more than offset by the proposed change to the Secondary Price Cap. SPC revenues constitute a significant portion of net revenues (after fuel costs) for non-variable renewable energy plants and should be factored into any updates to price settings.
- As the share of fixed costs within the WESM cost structure increases, this trend is expected to continue with rising RE penetration. The Primary Price Cap (PPC) and SPC are crucial for fixed cost recovery in WESM, given that it operates as an energy-only market.

- Price settings should be forward-looking to account for the potential persistence of high fuel prices supporting base revenues and the impact of increased VRE penetration on revenues.

These findings highlight several key dynamics to be addressed in Deliverable 4, including: (a) how price cap settings should be adjusted to support an evolving energy mix dominated by variable renewable energy generation in the WESM, (b) the revenue implications for existing and new entrant generators under the proposed amendment to the secondary price cap, and (c) the appropriate level for price settings to incentivise the required new entrant outlook, particularly in light of shifting cost structures toward a growing proportion of fixed costs.

4 Approach and Scenarios

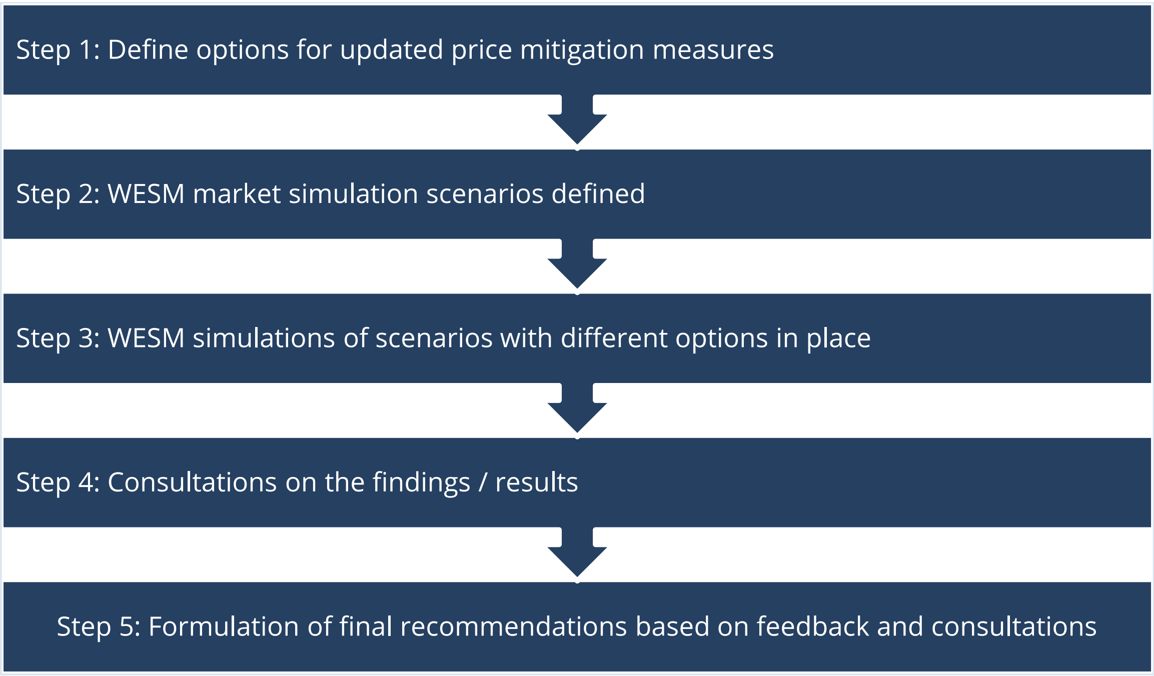
4.1 Approach

Reforms to the WESM price caps should aim to encourage efficient investment in future generation needs while considering the commercial outcomes for existing generation investments in the context of regulatory stability. The assessment in Report 3 of generator revenues, based on historical periods, highlighted the potential revenue risks associated with updating the existing price cap settings in the WESM. It is crucial to extend this assessment to cover the forward-looking reforms to price settings and incentivise investment in the intended capacity mix over time.

As the cost structure of the WESM evolves with higher renewable energy (RE) generation targets, increased volatility is anticipated due to the rising share of intermittent generation resources. This shift also underscores the growing need for peaking or firming generation options. The modelling and analysis conducted in this report supports a review of the current methodology for setting price caps and updating their values in alignment with promoting the WESM's future supply outlook.

Recognising the necessity of basing price caps on projected development and generation outcomes, Deliverable 4 is based on detailed market simulations for the 2025–2030 period. The approach to determining the optimal price settings and revenue dynamics is illustrated in Figure 5.

Figure 5 Summary of Approach



4.2 Scenarios

The options for price mitigation measures have been informed by the analysis in Deliverable 3. The three (3) scenarios proposed are discussed below and summarised in Table 2.[1] The main assumptions are listed in the table but discussed in more detail in Section 5.

- Scenario 1: Status Quo – no changes to the PPC, MPF and SPC. This is essentially the Base or reference case against which performances of other options can be assessed.
- Scenario 2: Alternative parameterizations of PPC, MPF and SPC. This scenario specifically models the proposed amendment to the secondary price cap based on an indexed administered price cap and extending the threshold upon which the secondary price cap triggers. The analysis in Deliverable 3 suggested current SPC levels were triggered too frequently, potentially stifling necessary price signals for new entrant investment.
- Scenario 3: Optimal parameterizations of price mitigation measures. This scenario specifically explores what the optimal PPC needs to be, assuming the amended SPC from Scenario 2 is included, to ensure revenue adequacy across all generation types that are likely needed over the forecast horizon. It may also be influenced by adjustments that would be more suited to modern technology mixes – e.g. as characterized by hybrid systems (variable renewable energy plant + energy storage) and energy storage in general. For example, primary price caps that consider storage duration.

Table 2 Proposed Base Scenarios

Assumption	Scenario 1 (Base)	Scenario 2 (Proposed SPC Amendment)	Scenario 3 (Optimal PPC)
Primary price cap	Current price settings applied to the generator offers. Price Cap: 32,000 Php/MWh Price Floor: -10,000 Php/MWh	Current price settings applied to the generator offers. Price Cap: 32,000 Php/MWh Price Floor: -10,000 Php/MWh	Increase price cap and apply to the settlement prices (parameter to be determined after Scenario 1+2 findings). Refer to Section 4.6.
Secondary price cap	Retain price cap settings: SPC: 6,245 Php/MWh CPT period: 3 days CPT threshold: 9,000 Php/MWh	Adjusted price cap settings: Base SPC: 9,852.6 Php/MWh (indexed) CPT period: 7 days CPT threshold: 13,657.38 Php/MWh	

[1] Additional sensitivities or scenarios may follow.

Committed and Indicative generator capacity outlook	Capacities for committed generators are considered in the outlook until 2030. Prospective new build capacities are also considered, as required, based on indicative plant list as per the PEP 2023-2050 outlook (to 2030).
Demand outlook	Demand Projections from the Philippine Energy Plan (2023-2050) based on projected 5.2% GDP Growth.
NREP to 2030	Target 35% Renewable Energy shares by 2030.
Generator costs	Capital costs per technology specific to the Philippines based on using historical project costs and applying the learning curve obtained from the forecast in the 2022 US National Renewable Energy Laboratory (NREL) Annual Technology Database.
Fuel prices	Base year prices are derived by interpreting the 10-band bids (reference year 2023) to identify the SRMC band, which serves as the basis for estimating coal, diesel and bunker fuel prices and are held constant to 2030. Gas prices are based on public estimates.[2] All gas-fired units are assumed to transition to LNG by 2027.
Contract levels	Historical 2023 contract levels by Generation Type based on aggregated contract information for Luzon, Visayas and Mindanao.
Bidding behaviour	Based on representative bids by type, region, time of day and scaled in line with the price settings.

The options have been initially assessed against key criteria to ensure that price signals effectively support investment in the Philippines' power development outlook. This includes ensuring revenue adequacy for both new entrant and existing generators while maintaining reasonable impacts on residential tariffs. Additional criteria used to evaluate the scenarios include: (1) promoting market efficiency and competition, (2) safeguarding against excessively high or low prices, (3) aligning with the overall WESM market design, and (4) feasibility of implementation. These assessments may result in some options being revised or prioritised lower than others.

4.3 WESM and Retail Market Modelling

When using power market simulations as the basis for making changes to the parameterisation of market price mitigation measures, care must be taken to: (1) isolate the key variables to ensure the modelling exercise performs an inferential function in the decision-making process, (2) reflects the most important market dynamics that are relevant, and (3) be suitably robust to ensure it will allow for the evaluation of the pros/cons of competing market design options. Often judgments are required to simplify elements of the electricity market design to simplify issues that are not relevant to the market design changes that are being "tested".

[2] https://www.bworldonline.com/corporate/2024/10/01/624877/local-gas-focus-seen-to-offset-imported-lng-prices/

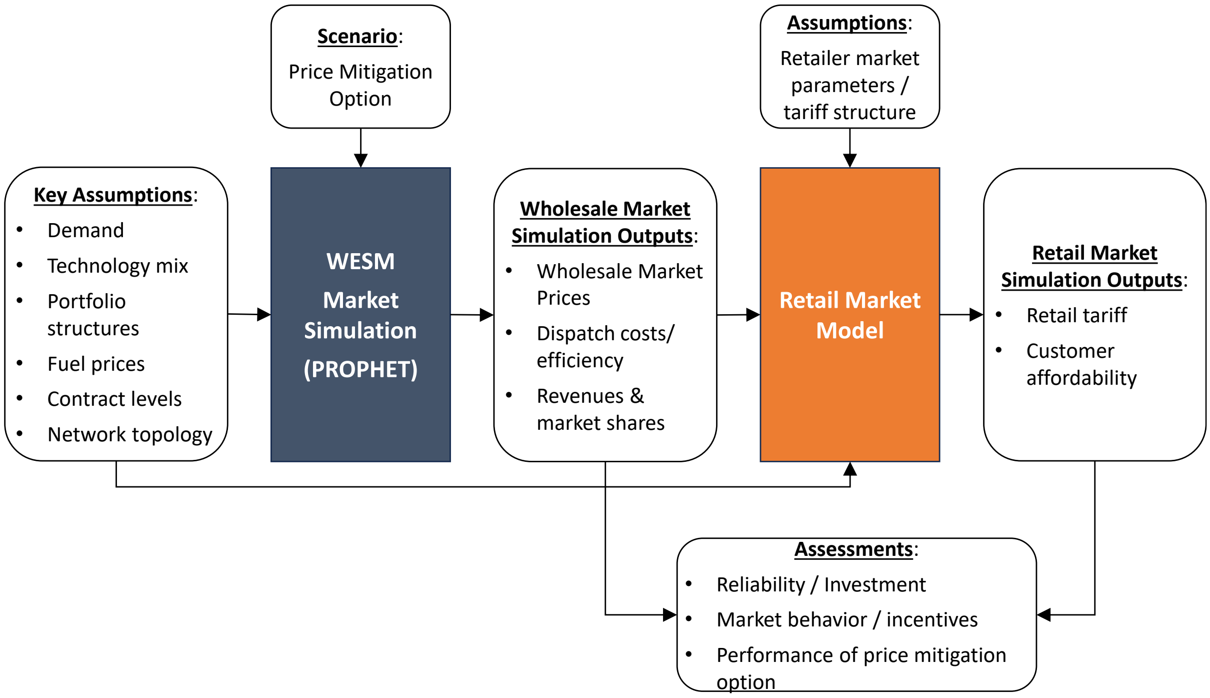
The requirements of the power market simulation to address the scope of work include:

- Formulation of **key assumptions** in assumptions spreadsheet – including demand, generation (and underlying costs), portfolio ownership structures (to reflect the competitive landscape of the WESM), contract levels, bids & offers and network topology.
- **Wholesale market simulation** – WESM operation – which would be based on bids / offers of generators, existing rules for management of RE generators, bidirectional offers from storage, and others – this would be done based on analysis of typical offers / structures and determining their reaction to changed market conditions – using freeware licenses of IES's PROPHET power market simulator, and
- **Retail market simulation** – which would primarily be concerned with estimating the impact of changed parameterizations of the market mitigation measures on the retail market, and retail prices that consumers face, to determine the impact on consumers of changes to the price mitigation measures. The analysis will need to also consider the varying levels of spot to contract purchases which will impact the retail rates.

A schematic of the general approach to simulation of the wholesale and retail markets of the Philippines is shown below in Figure 6. The model will represent the current and future state of the system with respect to different price cap settings. The objective is to see the impact of this on several aspects of the WESM:

- Output 1: The overall level of volatility from a change in generator bidding (as a function of the settings).
- Output 2: Net revenue levels (and cost recovery) of existing plants, and prospective plants. The analysis to be conducted per generator type across spot and contract revenues. The definition of revenue adequacy is defined as spot and contract revenues meeting the generators' variable (VOM and fuel) and fixed (FOM and annualised capex) costs.
- Output 3: Retail tariff implications assuming a fixed supply outlook (least cost and meeting reliability standard).

Figure 6 WESM Market Simulation Framework (using PROPHET)



Additional assessments across the scenarios will be made to explain the key indicators above and include:

- Market efficiency change (whether total spot market dispatch costs increase or decrease),
- Changes in distribution of revenues between different technologies (solar, wind, BESS, hydro, coal, gas, etc.),
- Changes in distribution of revenues between different market participant trading portfolios,
- Changes in the incentive for new entrants and hence the implied power system reliability change,
- Impact on retail tariffs (and therefore impact on customer bills and affordability),
- Changes in wholesale electricity market price distributions, and
- Changes in incentives on market participants.

Collectively these assessments enable informed decisions to be made and the relative dynamics between one set of price mitigation measures and another, thereby covering issues that are critical in the decision to change the price mitigation measures / parameters.

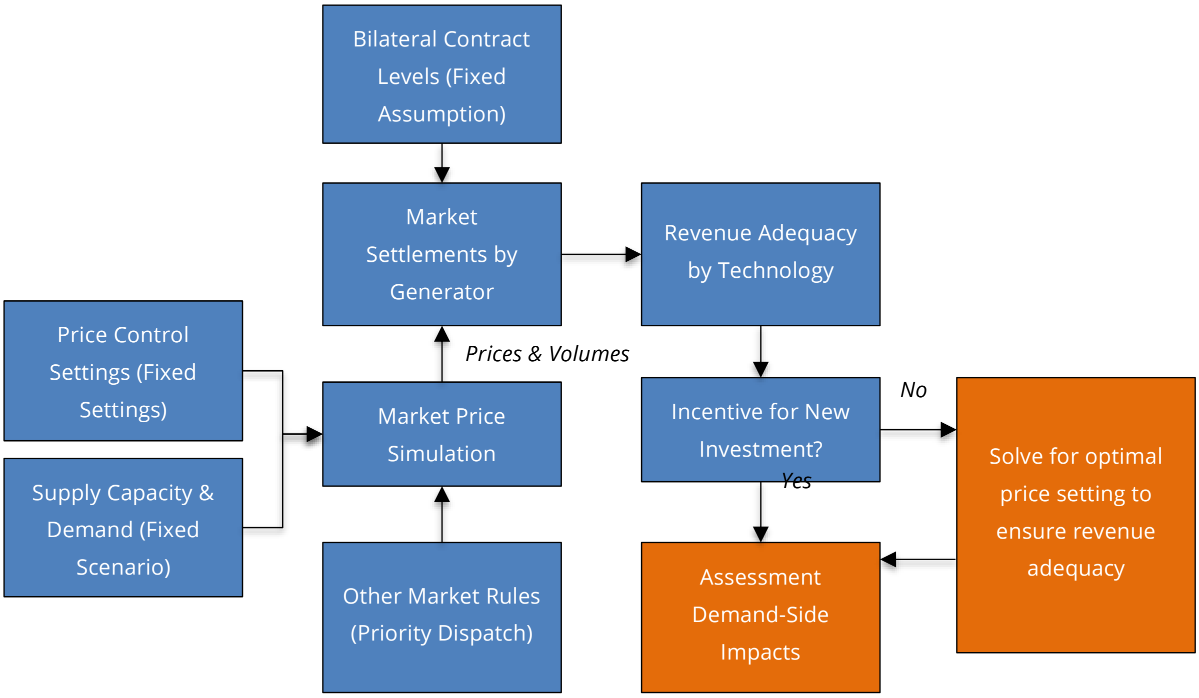
4.4 Market Simulation Method

The market simulation process explores the price volatility and revenue dimension of the key scope questions, and ultimately addresses whether new entrant revenues are adequate, i.e., are new entrants incentivised under the modelling price cap settings. The market simulation software used is IES' Prophet model which replicates the WESM dispatch engine. The main inputs into the model include:

- **Price cap settings**: the combination of PPC, MPF and SPC parameters we are modelling WESM outcomes against. This is the only assumption that differs across the scenarios.
- **Supply and demand outlook**: based on the expected/desired capacity development outlook. The approach assumes the capacity outlook is compliant against the WESM's reliability standard. This is a critical assumption as oversupply of capacity (or higher reliability standard than intended) will result in depressed pricing outcomes and a higher price cap settings to address.
- **Fixed bids**: representative of historical bidding for each generator type is used to ensure consistency and comparability across the scenarios. However, the bids are scaled in accordance with the assumed PPC parameterization.
- **Other assumptions**: market rules and arrangements, contracting levels, fuel prices, fixed and variable operating costs, annualised capex, network topology and transmission development, amongst other assumptions are all held constant.

The inputs into the market simulation are illustrated in Figure 7 below. Ultimately, there is a question of whether Scenarios 1 and 2 incentivise new entrant investment, and if not, what should be the PPC and SPC to deliver revenue adequacy.

Figure 7 Incentives for Supply-side Investment



Forecasting prices and generator responses is inherently challenging. To enhance the reliability of forecasting, IES has conducted a backcasting exercise to ensure the model's reasonableness and efficacy. Backcasting validates that the model closely reflects actual market conditions by replicating historical outcomes. This process also tests the accuracy of using representative bids and offers, assessed against key metrics such as pricing, volatility, generation volumes, and revenues. While some differences are expected due to unmodelled factors like outages (both network and generator), simplified transmission details, and the energy-only modelling approach, the goal is to present the overarching dynamics of generator revenues, which depend on generation volumes and pricing.

4.5 Prophet Model Settings

The wholesale market model emulates the WESM based on using PROPHET power market simulation package. PROPHET simulates WESM spot price outcomes under different choices of price mitigation parameters and measures. Key outputs from the wholesale market model for each scenario are:

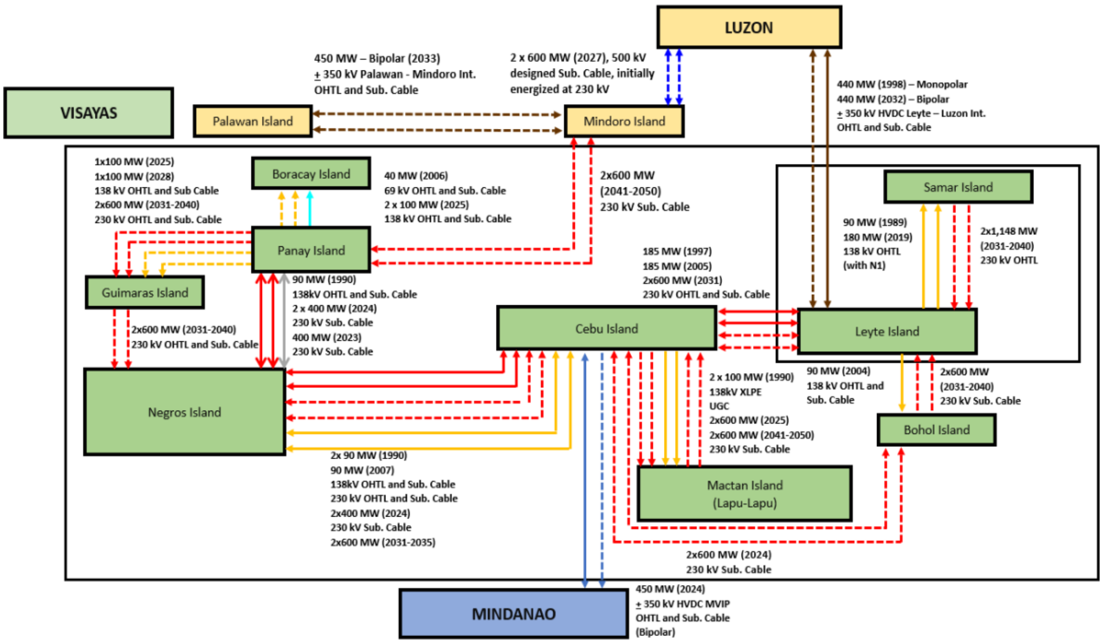
- Wholesale spot market prices (GWAP),
- Dispatch outcomes for generators,
- Generator revenues and total dispatch costs,
- Wholesale market shares, and
- Other indicators of market power and market efficiency.

Table 3 summarises the Prophet model and settings used.

Table 3 Prophet Model Settings

Assumption	Approach
Resolution and horizon	2025 to 2030, at 30-min resolution.
Services	Energy-only, reserves are excluded
Capacity retirements	No economic or fixed retirements considered to 2030
Generator bidding	Calibrated to 2023 spot price outcomes. This will implicitly account for portfolio ownership structures.
Generator parameters	Based on data provided by PEMC
Generator technical constraints	Minimum stable levels of thermal plant, ramp rates, outage and maintenance rates
Network model	3-region and 7-node configuration (Luzon, Mindanao, and Visayas sub-regions namely: Leyte-Samar, Cebu, Negros, Panay, and Bohol)
Network state and constraints	Transmission Development Plan 2024-2050 (see Figure 8). Only thermal limits are modelled, no outages
Market arrangement	No change to the current market arrangements other than changes to the price cap settings per scenario
Bilateral contract volumes	Per generator type per region based on historical year 2023.

Figure 8 Network Topology



Source: Transmission Development Plan 2024-2050 – National Grid Corporation of the Philippines.

4.6 Optimal Price Settings

Scenario 1 is used as a baseline for comparison to assess Scenario 2 (new proposed SPC). Given the likelihood that the amended SPC (Scenario 2) and corresponding WESM pricing outcomes will not adequately compensate generators for investment and operational risks, Scenario 3 (optimal PPC) explores what the minimum PPC is to ensure all new entrants are revenue sufficient. This involves the following steps:

- Run Prophet model to assess generation and revenue outcomes based on representative bidding dynamics (as a function of the set of price settings).
- Based on the (spot and contract) revenue outcomes, assess whether generators (new and existing, and aggregated by type) are revenue sufficient, i.e., both variable and fixed costs are covered.
- Solve for what the price settings need to be to ensure new entrants are incentivized (can recover costs). This calculation is performed outside of Prophet and then validated through a final run of the Prophet model. The solve ensures no significant over or under-recovery of revenues, i.e., provides an efficient outcome. See Section 5.6 for the definition of revenue adequacy.
- The spot prices (corresponding to the solved price settings) and contract prices will impact the generation cost component of the tariff. As the PPC and volatility increases, contract prices need to also shift in accordance with implied risk for the seller.

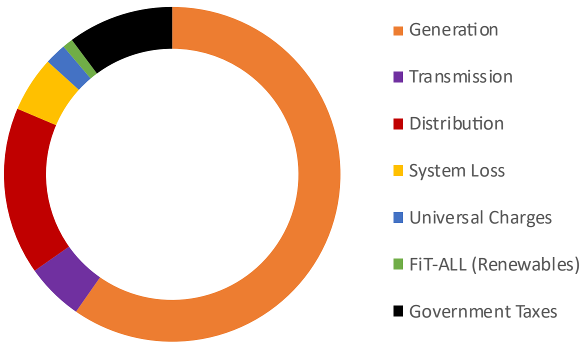
Figure 9 Solving for the Optimal PPC

Base simulation with assumed set of price settings	Test new entrant (and existing generator) viability	Solve price settings to ensure efficient revenue recovery	Assess impact on residential tariff
1. Run Prophet model to assess generation and revenue outcomes based on representative bidding dynamics (as a function of the set of price settings).	2. Based on the (spot and contract) revenue outcomes, assess whether generators (new and existing, and aggregated by type) are revenue sufficient, i.e., both variable and fixed costs are covered.	3. Solve for what the price settings need to be to ensure new entrants are incentivized (can recover costs). The solve ensures no over or under-recovery of revenues, i.e., provides an efficient outcome.	4. The spot prices (corresponding to the solved price settings) and contract prices will impact the generation cost component of the tariff.

4.7 Retail Tariff Modelling

The tariff modelling focuses on the residential end-user tariff in the WESM on a theoretical system-wide basis. The tariff modelling specifically assesses the impact of different price cap settings (scenarios 1-3) on the generation cost component of the tariff. All other components are assumed to remain constant over the horizon. For the August 2024 billing period, the generation cost component of the Philippines residential electricity tariff is the largest component and comprises approximately 59% of the total tariff (see Figure 10).

Figure 10 Residential Electricity Tariff Component Share (MERALCO 2024)



The generation cost component reflects the cost of energy delivered from a generator's node and excludes transmission and distribution losses. Reserve and other ancillary service costs are also excluded in the modelling. The generation cost component is assumed to be based on a mix of spot exposure and bilateral contract prices. Majority of the energy transactions in the market are still entered in bilateral contracts as spot market transactions comprise only 22.91% of the total transactions for 2024[3]. To calculate the overall cost of serving a residential load the following are also considered:

- The typical residential profile shape. Note that we can only do market-wide assessment as we don't have the individual loads & net contract positions of each retailer,
- Spot price and volatility exposure (different per scenario based on price cap setting assumption),
- Optimal mix of contracts to hedge the residential load,
- Estimated contract prices based on the modelled spot market outcomes with a risk premium applied,
- Tariff impacts calculated at system level only.

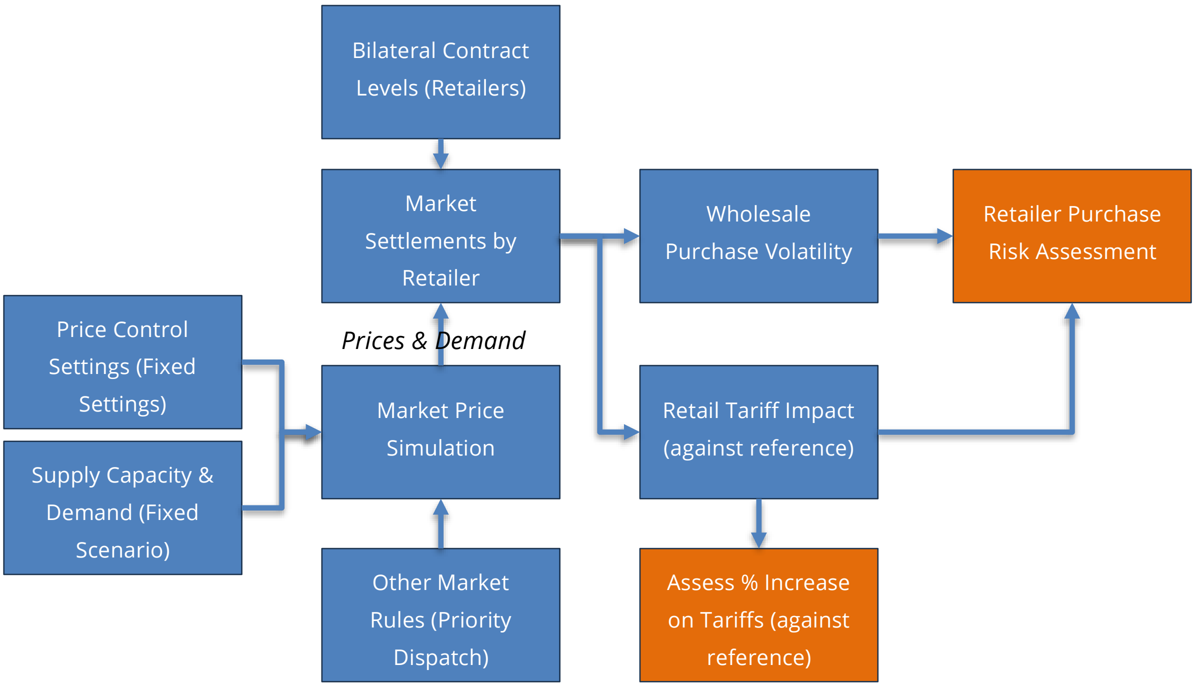
Figure 11 illustrates the relationship between retail tariff modelling and wholesale market modelling. The tariff modelling will be based on computing the overall percentage change in tariffs across the scenarios. While higher price cap settings are expected to result in higher tariffs, it is important to consider that lower price caps, which fail to adequately incentivise capacity, could lead to a less reliable system. This, in turn, tends to be more costly for all end-users on an economic cost basis.

A cost related to the level of reliability is therefore also important to capture in the tariff impact assessment. This is simply a weighted average of demand served and demand not served against the respective cost, where:

- Demand that is served is costed at the spot and contract cost, which will be impacted by the level of the PPC, and
- Demand not served is costed at the value of customer reliability. The value of customer reliability is effectively the price at which consumers are willing to pay to avoid disruption.[4]

[3] Annual Market Assessment Report 2024 - PEMC
[4] This would normally be determined through a survey across a range of end-user types. However, for the purpose of this exercise, this value has been assumed to be 64,000 Php/MWh.

Figure 11 Impact on Retailer and Consumers (Demand-side)



4.8 Modelling Limitations

Steps were taken to ensure the accuracy of the model by comparing its outputs against the actual historical outcomes, including, but not limited to average prices and generator capacity factors. The PROPHET model was designed to simulate the energy-only market as the available actual data, which serve as the baseline for model testing, are specific to an energy-only setup. The following lists the identifiable limitations of the model:

- Reserve market dynamics are not captured in the pricing outcomes and reserve revenues are not considered in the total generator revenue calculations.
- Contract levels, which does drive volatility, are based on historical 2023 levels.
- The capacity development outlook is assumed to deliver the reliability standard in the WESM. Over or under-supply will drive the optimal level of the PPC needed to address revenue certainty.
- The definition of revenue adequacy, currently assuming a single system portfolio for new entrants only, impacts the optimal PPC.
- Pumped hydro and battery storage units use a 'Predispatch' functionality for bid offers in Prophet that optimises dispatch for storages and overrides any 2023 fixed bids for these units.
- Transmission lines are manually augmented across the forecast period based on examining the congestion across the interconnectors on an annual level across both directions whilst minimising excessive price differentials between regions

- Due to the lack of detailed hydro reservoir parameters and the use of fixed bids (instead of accounting for the marginal cost of water), hydro generators have been modelled without reservoirs. As a result, the bids primarily drive adequate utilisation.
- Generator bidding patterns and how these may respond with a change in the PPC is a material driver of generator revenues and the required PPC outcomes. The modelling assumes all price bands above 10,000 Php/MWh will shift linearly with a change in the PPC.
- Fuel price assumptions drive net revenues, particularly for VRE that comprise most of the new entrant portfolio that is modelled, and can be volatile particularly with the shift to imported LNG in the WESM.
- The impact of increased VRE penetration, particularly for solar investment, as generation is concentrated during the middle of the day, which could drive prices lower.

5 Assumptions

Assumptions to the PROPHET model are outlined to provide basis for analysis and ensure alignment with the set targets in the development plans. The results of the modelling under these assumptions are tested against the actual 2023 data to assess the accuracy of the model and provide confidence in the forecasted values (results provided in Section 6).

5.1 Data Requirements

The main data requirements for the market simulations will be:

- Historical bids / offers for sample periods over the period 2020-2023,
- Key transmission congestion points / constraints – typically generation group limits / constraints,
- Historical Regional Demand,
- Historical outages / generator availabilities,
- Wind and solar generation profiles,
- Historical Locational Marginal Prices (LMPs) and GWAPs,
- Kalayaan pumping load profiles, and
- List of registered market participants and their power stations month by month.

The 2023 historical market data, Philippine Energy Plan (PEP 2023-2050) and the Transmission Development Plan (2024-2050) are the main basis for the data inputs. The summary of the PROPHET model inputs, and their sources are presented in Table 4.

Table 4 Database Inputs

Database Input	Source / Description
1. Demand Profile	Based on forecasted demand from the Philippine Energy Plan (PEP 2023-2050)
2. Generation Technologies	New entrants, including energy storage (pumped storage hydro and batteries) based on DOE list of Committed and Indicative Power Projects (as of May 2024) and PEP Outlook.
3. Transmission Information and Constraints	Current limits and augmentations based on Transmission Development Plan
4. Outages	Historical Data and Maintenance Plans
5. Generation Profiles	Historical Data for Wind and Solar Plants
6. Bilateral Contract Levels	Exposure to price volatility and impact on bidding behaviour
7. Short-run Marginal Prices	Based on the fuel price scenario
8. Generator Bidding	Historical offer profiles expressed as a function of the price settings
9. Other Constraints as per WESM Rules	Reflect changes with the market rules

5.2 Proposed SPC Amendment

The current secondary price cap (SPC) is based on a simple mechanism, using the rolling average of the generator weighted average prices (GWAP) from the past 3 days compared against the set cumulative price threshold (CPT) of 9,000 Php/MWh. The proposed amendment to the SPC involves both an update to the cap itself and changes to the mechanism of triggering it. The details of the proposed amendment are summarized in Table 5.

Table 5 Proposed Amendments to the Secondary Price Cap[5]

Parameters	Current Setting	Proposed Amendment
SPC Value	6,245 Php/MWh	9,852.6 Php/MWh, calculated using the levelized cost of energy (LCOE) of the best new entrant for peaking plants, determined to be LNG single cycle gas turbine.
Cumulative Price Threshold (CPT)	9,000 Php/MWh	13,657.29 Php/MWh, based on a typical price spike day as proposed in the SPC amendment.
Rolling Average Window	3 days	7 days
Supply Margin	Not considered	Triggers SPC when the supply margin is less than 15%.
Updating method	Not updated	• SPC value is updated quarterly based on LNG prices and economic indices, including foreign exchange rates and Philippine Consumer Price Index • CPT is fixed

The supply margin as basis for triggering the SPC is not incorporated in the model as this setting could potentially result in the price cap not effectively protecting the consumers against market manipulation. Additionally, the amended SPC value is not adjusted in the forecasted years as the fuel prices are assumed to be constant throughout the forecast horizon.

5.3 New Entrant Generation

The assumptions for the new entrants are based on the supply outlook from the Philippine Energy Plan (PEP 2023-2050) and the list of committed power projects published by the Department of Energy (DOE) in May 2024. Additional capacities were modelled on top of the committed project pipeline through 2030, using the data from the indicative project list. Table 6 summarises the forecasted new entrant capacities considered in the PROPHET Model.

[5] ERC Case No. 2023-008-RM, IN THE MATTER OF THE PETITION TO INITIATE RULE-MAKING FOR THE SUSPENSION OF ERC RESOLUTION NO. 07, SERIES OF 2021 AND THE ADOPTION OF THE PROPOSED RULES ON THE IMPOSITION OF SECONDARY PRICE CAP – PHILIPPINE INDEPENDENT POWER PRODUCERS ASSOCIATION, INC.

Table 6 New Entrant Capacities

Technology	Existing Capacity by 2023, MW	Committed by 2030, MW	Indicative projects modelled by 2030, MW
Coal	12,406	405	0
Oil Based	3,737	65	0
Natural Gas	3,732	0	3,570
Biomass	585	54	62
Geothermal	1,952	84	385
Solar	1,699	4,281	1,089
Hydro	3,800	134	160
Wind	427	2,063	1,180
BESS + PHES	436	530	1,440
TOTAL	**28,822**	**7,615**	**7,886**

Variable Renewable Energy (VRE) capacity is projected to dominate the new entrant capacity, with solar alone accounting for 56% of the committed capacity mix. Several wind projects are also included in the indicative pipeline, totalling 30 GW, with some uptake likely driven by the aspired target of 35% renewable energy share by 2030. Considering the combined capacities of existing and committed power projects, the VRE capacity share is expected to reach 23% by 2030. Geothermal and Biomass are anticipated to see small expansions by 2030 while hydro and energy storage systems, including batteries and pumped hydro, are expected to provide firming support for increasing VRE capacity.

A total of 7.6 GW of new generation capacity is committed and set for operation in 2027. Despite this, IES brought some generators from the indicative list online ahead of their target commercial operation dates to address potential unserved energy in certain regions or nodes. Figure 12 shows the total yearly capacities assumed in the PROPHET model. The capacity mix, relative to the system peak demand, maintains an average reserve margin of 17.5% over the forecast period, indicating a balanced supply-demand scenario. It is important to note that only a few indicative projects have been brought online; they serve as reference points as needed to meet the growing demand. Figure 13 highlights the breakdown of indicative and committed new entrant technologies considered in the model.

Figure 14 shows the new entrant capacities across the three regions. At the regional level, new entrants in Luzon comprised 69% of the total new capacities equivalent to 15.5GW, reflecting its significant demand and supply needs. Moreover, Visayas new entrants accounted for 21%, addressing the regional reliability and balancing requirements while the remaining capacity share of 11% is for Mindanao.

Figure 12 Modelled Capacities

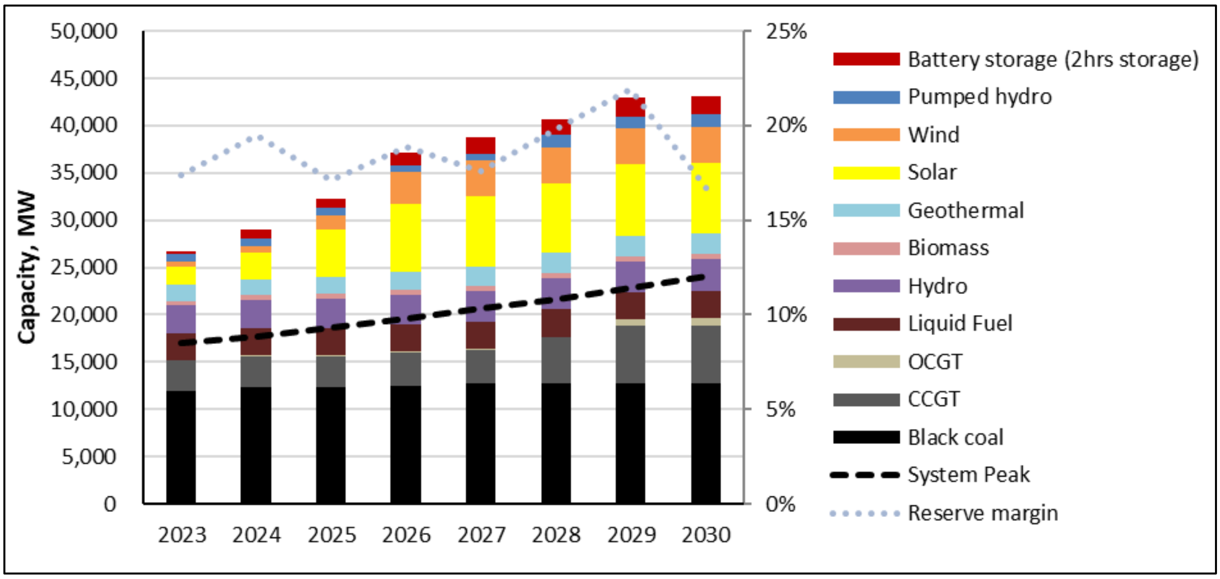


Figure 13 Total New Capacities by Type

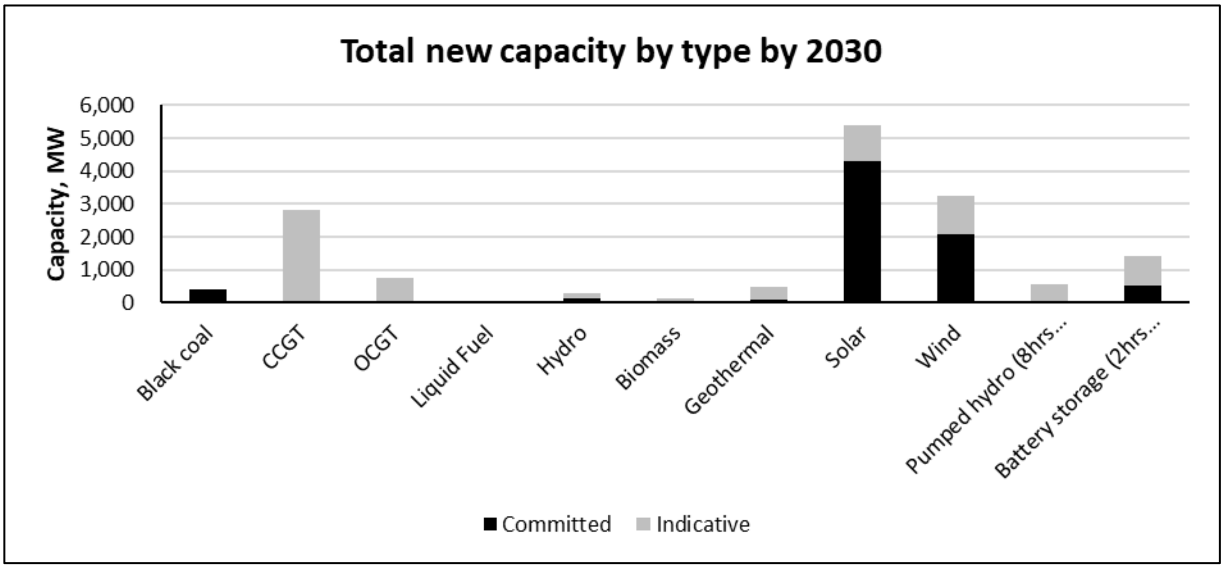


Figure 14 Modelled New Entrant Capacities per Region

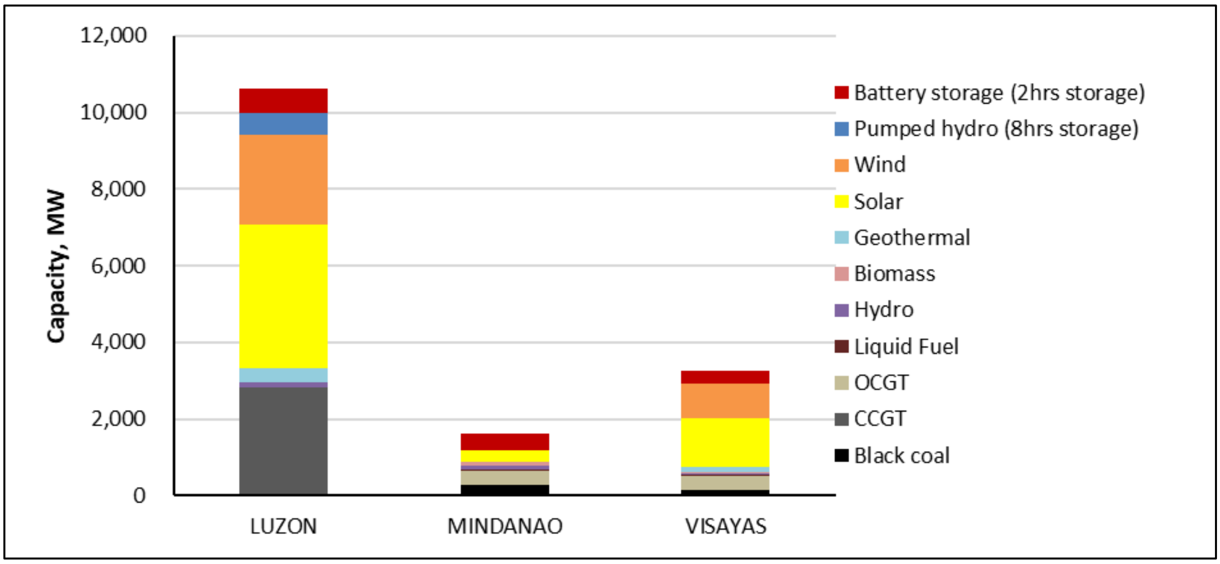
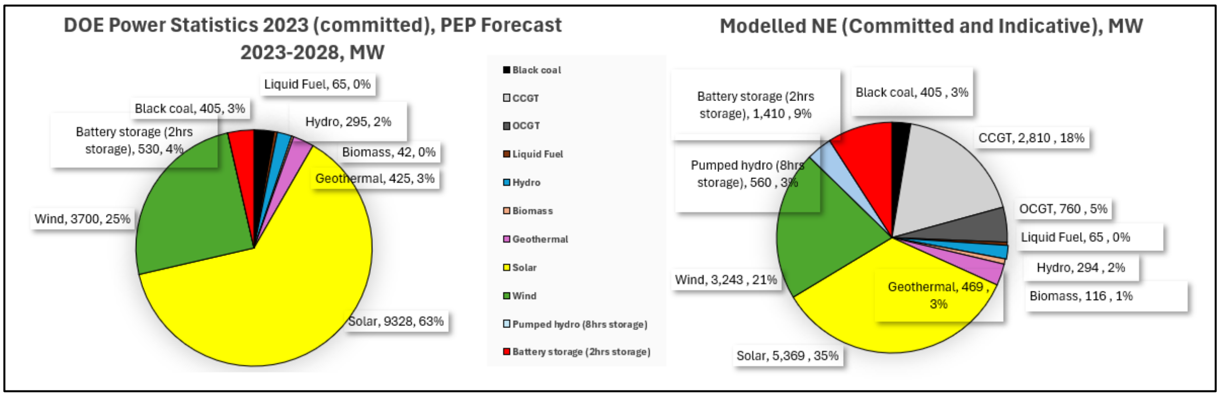


Figure 15 shows the comparison of the forecasted capacities from the PEP Outlook and DOE Committed and Indicative Power Projects as of May 2024 against the modelled capacities. From the forecasted capacities, variable renewable energy (VRE) such as solar and wind are projected to form the highest share of the new entrant capacities, with solar alone accounting for more than half of the mix at 63%.

Modelled capacity uptake exceeded the DOE Power Statistics (2023) and Philippine Energy Plan (PEP 2023–2050) Outlook to account for the addition of Combined-Cycle Gas Turbines (CCGTs) on Liquefied Natural Gas (LNG), as referenced from the national LNG Policy and the Indicative project list from DOE. This is in anticipation of increased reliance on LNG imports as domestic natural gas resources decline. Additionally, LNG is expected to replace and reduce the dependence of the grid on coal-fired power plants. The resulting capacity uptake in MW terms closely aligns with DOE's 2023 Power Statistics for committed projects and PEP projections but reflects a lower solar and wind share due to increased gas integration. Despite this, the renewable generation share remains close to the RE development target, achieving 34% as compared to the target generation share of 35% by 2030 (see Section 6.2).

Figure 15 Modelled New Entrant Capacities vs Forecasted Capacities



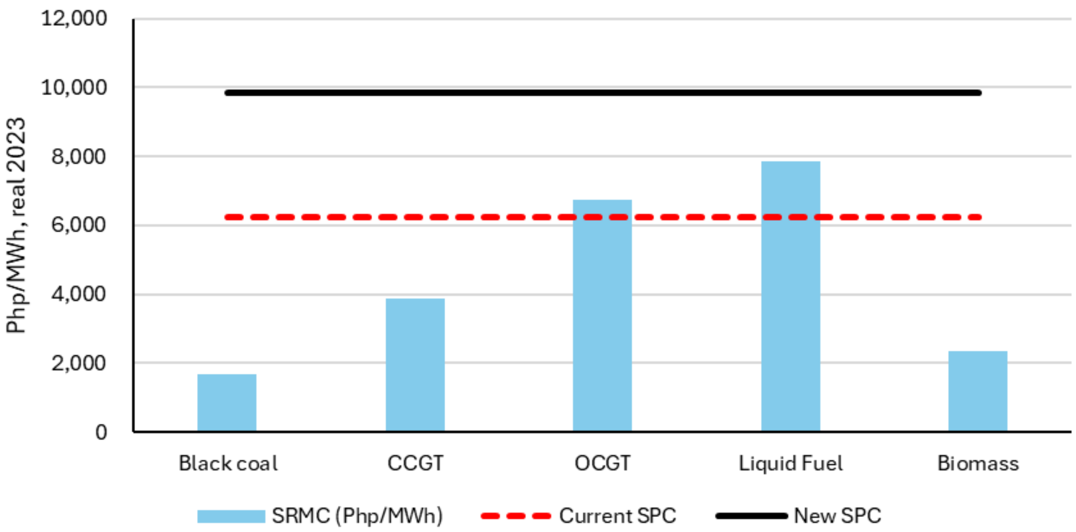
5.4 Generator Costs

The model incorporates generator cost assumptions, including fuel costs, SRMCs, and fixed costs, for evaluating cost recovery and pricing behaviour. Base year prices are derived by interpreting the 10-band bids (reference year 2023) to identify the SRMC band, which serves as the basis for estimating coal, diesel and bunker fuel prices and are held constant to 2030. Gas prices are based on public estimates.[6] All gas-fired units are assumed to transition to LNG by 2027.

The comparison of SRMCs with the current and proposed SPC highlights dispatch implications in Figure 16 below. Under the current SPC, OCGTs and liquid fuel plants have SRMC above what can be recovered through the spot market. This may lead to generators withdrawing capacity from the market which would be highly suboptimal given the triggering of SPC likely also points to periods of tight supply and volatility where capacity is needed.

The proposed SPC amendment comparatively provides additional headroom for most technologies to recover variable costs and minimises dispatch issues (and potential compensation) under the current SPC level.

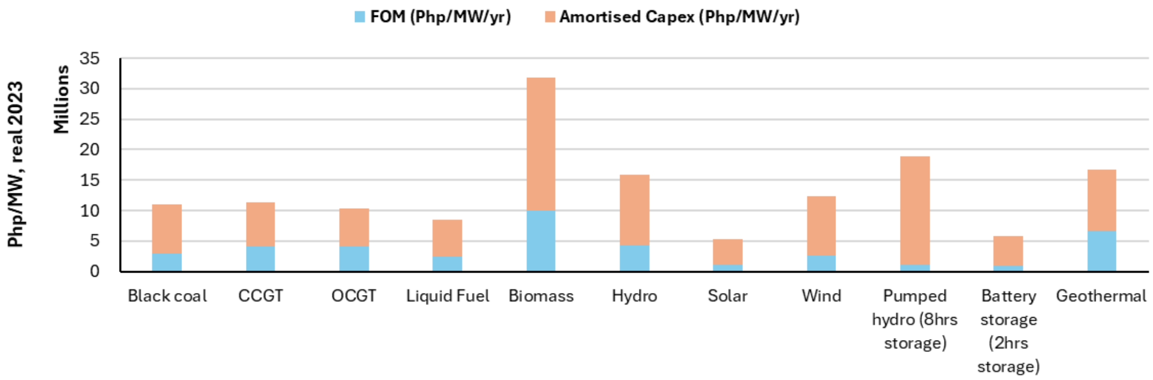
Figure 16 SRMC and Fuel cost by generator type (real 2023 Php)



Capex is a critical assumption and input into the market price settings. The approach taken is to use capex requirements in 2023 and scale these based on the NREL 2022 implied learning rates, consistent with the dataset used in the PEP. Several data sources were used as the starting point. These included PEMC data or more recent project costs.[7] Where such information was unavailable, the NREL 2022 capex values were retained. A summary of the annualised fixed costs are in Figure 17.

[6] https://www.bworldonline.com/corporate/2024/10/01/624877/local-gas-focus-seen-to-offset-imported-lng-prices/
[7] Capex data provided by PEMC was generally too outdated to be used in this work. This has implications for higher PPC requirements in order to address revenue adequacy.

Figure 17 Generator Capex and FOM costs by fuel type (real 2023 Php)



An optimal PPC would be expected to balance cost recovery effectively by providing sufficient revenue opportunities for generators to meet their cost base without introducing excessive price volatility. By aligning price caps with underlying cost assumptions, the model ensures that all technologies can recover costs sustainably while maintaining overall market stability.

5.5 Generator Bidding Behaviour

The generator bidding behaviour is modelled for each generator type and generalised based on the historical bidding patterns of online generators from 2023 calendar year. It is assumed that existing and new entrant generators adopt the same bidding behaviour throughout the forecast horizon. The steps taken to capture the generalised bidding behaviour for each generator technology in the WESM are summarised as follows:

- Develop a model that uses representative bids under current price settings to forecast generation prices and generator revenues. Note that due to the lack of intra-regional constraints, the initial backcast prices are expected to be low. To resolve this, bids would require uplifting across all bands to ensure resulting prices align with actuals, whilst minor adjustments would need to be made on certain bands based on technology type, to also maintain generation outcomes close to actuals.
- Determine the average nodal generator price offers in terms of the available capacity levels, in increments of 10% of the installed plant capacity.
- Filter out intervals where most of the units' nameplate capacity was not offered into the market to effectively remove any generator deratings in the bid representation.
- Battery and PSH bids to be optimised by the model. RE (solar/wind/geothermal) bid in MPF (or must-run).
- Grouping the generators per plant type, the average MW offers are determined to model a simplified network.
- The representative offers are determined specific to each Region, Technology, Year, Season, Day Type and Hour Type.

Representative Bids

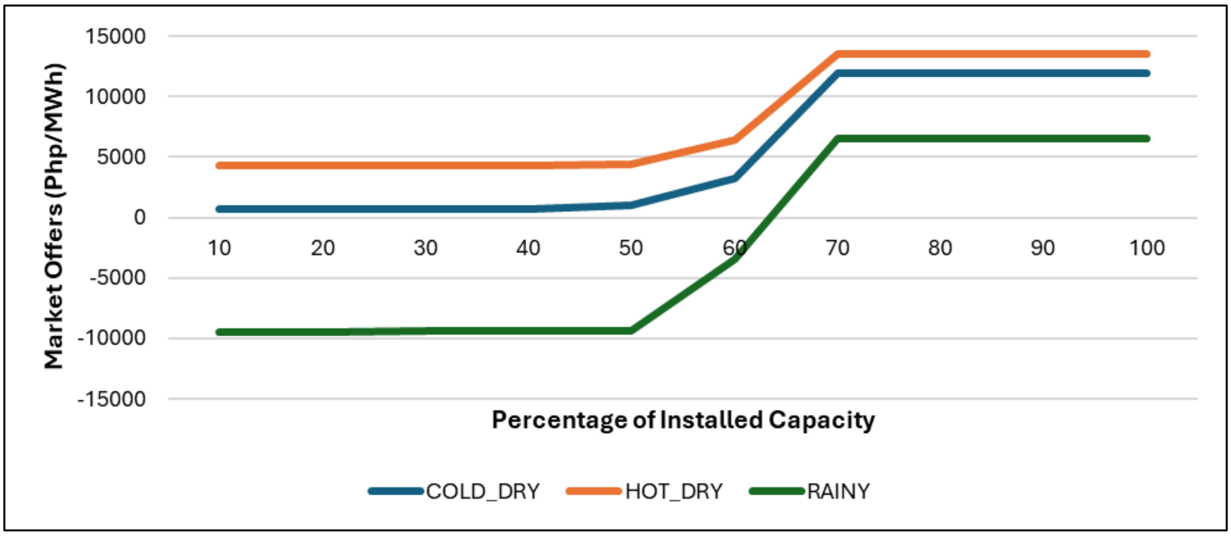
The PROPHET model uses these representative bids under the current price settings to simulate market dispatch dynamics, forecast generation prices, and compute for overall generator revenues. Table 7 summarises the details of the obtained representative bids specific to each generator technology.

Table 7 Generator Representative Bids

Generator Technology	Bid Type	Bid Structure
1. Thermal generators (Coal/Gas/Oil-fuel) 2. Geothermal 3. Hydro	Fixed Bids distinguished by: • Seasonality • Day type • Time-of-day • Fuel type	• Generalized representative generator offers consisting of 10 bid blocks for the capacities and offer prices. Each bid block reflects the generator capacities in 10% increments and prices based on the generator bidding patterns. • Although geothermal plants can now be classified as priority dispatch, resulting representative bids are generally close to 0 Php/MWh, and is essentially reflective of the changes in generator classification. • Hydroelectric plants, although eligible for priority dispatch, are still mostly registered as scheduled/bidding generators at the present.
4. VRE (Wind and Solar) 5. Biomass (currently modelled using actual bids, but in future references dispatched as priority-dispatch)	Bid at Floor Price and treated as MUST-RUN Generators. No Curtailment was allowed	• VRE generation profiles are based on the historical generation data of solar and wind generators in the WESM from 2021 until 2024. To model must-run classification in the WESM, capacities are offered at the price floor of -10,000 Php/MWh.
Battery & Pumped Hydro bids	Battery dispatch managed using a dynamic programming algorithm - selects optimal times to charge & discharge assuming prices follow expected price trace	

Since each region has a unique supply mix, certain regions may have new entrants without the existing technology (e.g., natural gas in Mindanao). To address this, the model is configured so that the new entrant adopts a bidding behaviour based on the average from the existing technology in other regions. Figure 18 shows the representative bids adopted by new entrant gas plants for Mindanao.

Figure 18 Sample Representative Generator Bids – Gas Plant



Bid Scaling

Having established the representative bids that capture the generator bidding behaviour, a method to scale explicit bids was developed to match the update in the primary price cap (PPC). The scaling method can be summarised as follows:

- For each generator, a 10,000 Php/MWh threshold is used to determine the offered MW capacities related to the existing price cap and price floor.
- The adjustment factor is then determined and based on how far the price offers on these MW levels are from the existing price cap. Only the incremental prices above the 10,000 Php/MWh threshold are scaled.
- Prices levels related to SRMC are unadjusted as fuel prices are assumed constant throughout the forecast horizon.

An example of representative bid scaling with the movement of the primary price cap from 32,000 Php/MWh to 64,000 MWh is shown in Table 8. The following formula is used for the computation of the resulting scaled generator bids at each capacity level:

$$Price_{scaled} = \frac{Max[(Price_{bid} - threshold), 0] \times (MPC_{new} - threshold)}{MPC_{old} - threshold} + Min(Price_{bid}\,, threshold)$$

Table 8 Representative Bids Scaling

Representative Gen Bids	10% Capacity	20% Capacity	…	100% Capacity
Gen A **(PPC 32k)**	-9,000	15,000	…	25,000
Gen A **(PPC 64k)**	-9,000	**22,272**	…	**46,818**

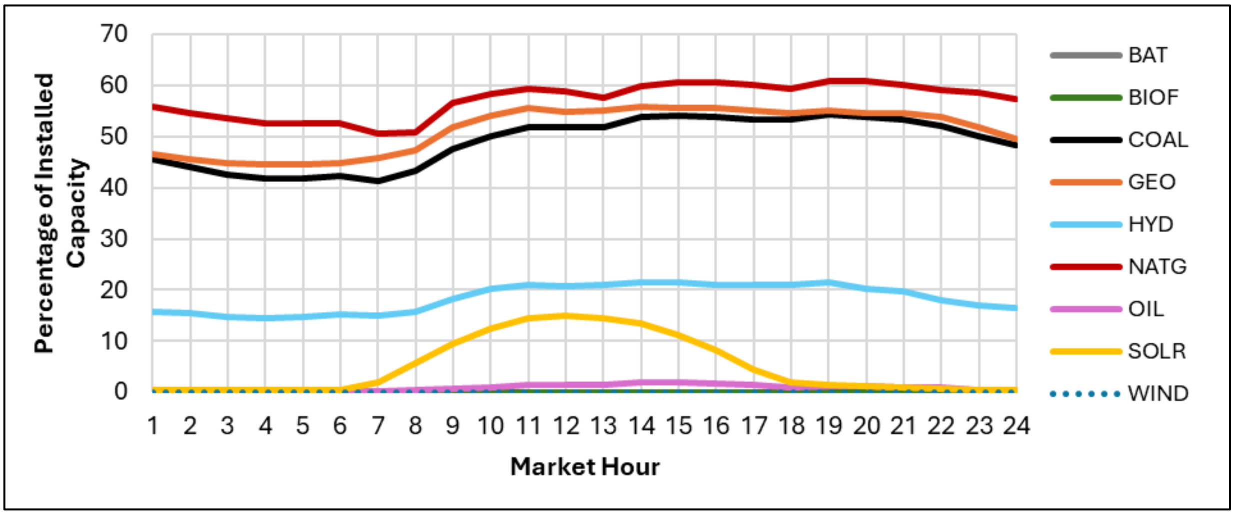
Gen A **(PPC 55k)**	-9,000	**20,227**	...	**40,681**

5.6 Bilateral Contract Quantities and Pricing

Contracting levels reflect the share of generator revenues that are hedged against spot market volatility, revealing if market price settings impact generator revenues, as well as tariffs. Higher contracting levels would suggest that changes in the price settings have minimal effect when most revenues come from bilateral contracts.

Figure 19 shows the average hourly contracting levels. These levels are determined for each region, season, day type, and generator technology based on 2023 historical data. Similar with the representative bids, new entrants adopt contracting profile at regional levels if the technology exists; otherwise, they follow the system-wide average. The obtained profile shows that gas plants rely heavily on bilateral contracts, with more than half of their installed capacities committed through such agreements. On the other hand, the majority of capacities for VRE, peaking plants (oil-based), hydro, and biofuels are uncontracted, indicating that most of their revenues are derived from the spot market.

Figure 19 System-wide Average Contract Profiles (2023)



Notes: 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.

Due to data limitations, the contract price is assumed to have a 10% risk premium based on the average baseload prices of the traded electricity futures contracts in the main regional Australian Electricity Markets of NSW, VIC, and QLD[8]. In the context of electricity markets, the risk premium is the difference between the forward contract price and the expected spot price, often paid as compensation for bearing price or demand risks. Empirical studies across various electricity markets, including those in PJM, Germany, and Australia, suggest that generators incorporate a premium to account for spot market risks in energy-only markets, with these risk premiums

[8] https://www.mq.edu.au/__data/assets/pdf_file/0007/583288/working_paper_16-03.pdf

ranging from 5% to as much as 14%. The 10% risk premium is applied to the settlement prices, and the contract revenues are calculated at each interval using the contract quantity shaped load-weighted price from 2025-2030.

The following formula is used to calculate for the load-weighted average prices for each generator technology in each region:

$$LWAP_{tech,r} = \frac{\sum_{g \in G_{tech,r}} Price_{ti,tech,r} \times Qty_{ti,tech,r}}{\sum_{g \in G_{tech,r}} Qty_{ti,tech,r}}$$

Where:

$LWAP_{tech,r}$: $Load\ weighted\ average\ price\ for\ generator\ technology\ tech\ in\ region\ r$

g: $generator\ resource\ g$

$G_{tech,r}$: $generator\ technology\ tech\ region\ r$

$Price_{ti,tech,r}$: $Price\ for\ time\ interval\ ti\ and\ generator\ resource\ g$

$Qty_{ti,tech,r}$: $contracted\ quantity\ for\ time\ interval\ ti\ for\ generator\ technology\ tech\ in\ region\ r$

The 10% risk premium is added to the computed load-weighted average prices and the resulting contact revenue for each generator technology in a specific region is calculated at each interval using the following:

$$BCQ_{ti,tech,r} = \sum_{g \in G_{tech,r}} Qty_{ti,tech,r} \times [LWAP_{tech,r} \times (1 + rp)]$$

Where:

$BCQ_{ti,tech,r}$: $Bilateral\ Contract\ Revenues\ at\ time\ interval\ ti\ for\ generator\ technology\ tech\ in\ region\ r$

g: $generator\ resource\ g$

$G_{tech,r}$: $generator\ technology\ tech\ region\ r$

$LWAP_{tech,r}$: $Load\ weighted\ average\ price\ for\ generator\ technology\ tech\ in\ region\ r$

$Qty_{ti,tech,r}$: $contracted\ quantity\ for\ time\ interval\ ti\ for\ generator\ technology\ tech\ in\ region\ r$

rp: $risk\ premium\ applied, expressed\ in\ \%$

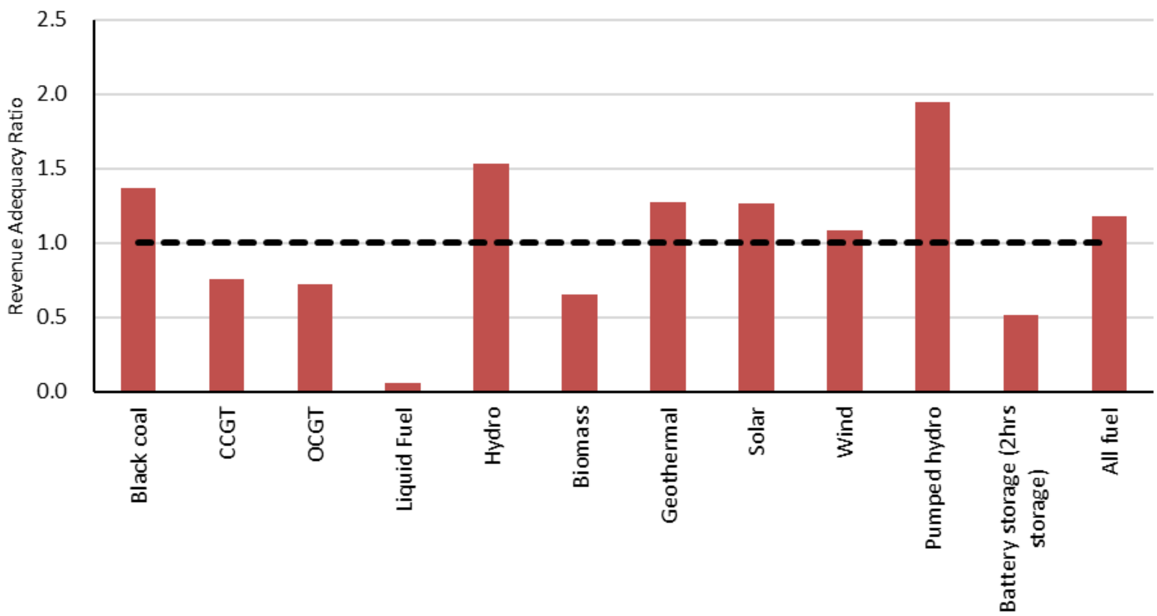
5.7 Revenue Adequacy Definition

The revenue adequacy ratio, defined as total revenue (spot and contract) divided by total costs calculated for new entrants across a single system portfolio, serves as a key indicator of whether a generation technology achieves sufficient cost recovery. A ratio above the threshold of 1.0 indicates that revenues exceed costs, signalling financial viability. Conversely, a ratio below 1.0 highlights revenue shortfalls, pointing to insufficient cost recovery under the current market conditions.

This ratio plays a critical role as a basis for assessing the economic sustainability of generation technologies. It is used to evaluate whether market price settings and revenue streams, such as spot prices and contracts, provide adequate returns to justify operational and investment decisions.

Figure 11 provides an example of how the revenue adequacy ratio is applied to existing plants. By comparing the ratios for different technologies against the threshold, it becomes evident which technologies recover costs sufficiently and which face challenges. This assessment serves as an essential tool for identifying gaps in cost recovery, informing on market adjustments, such as changes to the SPC or PPC, to ensure that price settings align with the system's overall economic requirements and balance overall market outcomes.

Figure 20 Cost recovery of existing generators 2025-2030



5.8 Retail Tariff Modelling Assumptions

The impact of various market price settings on the retail tariff is assessed to determine how price adjustments, aimed at ensuring generator revenue adequacy, affect the consumers. Retail tariff modelling evaluates how these price settings influence the generation cost component. The following are the assumptions considered in the tariff computation:

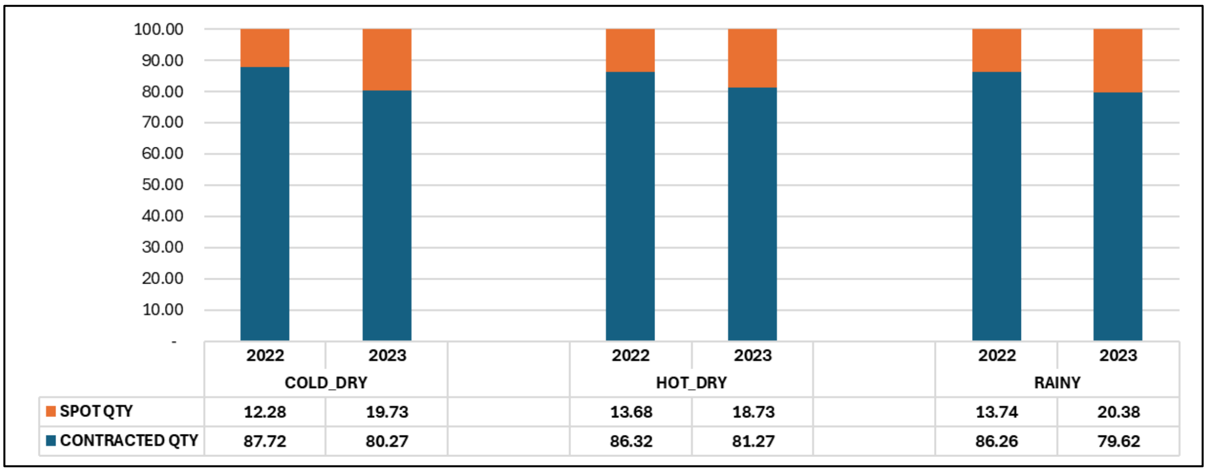
- The generation cost component is assumed to be a mix of spot exposure and bilateral contract prices. The level of hedging against the volatility of the spot market is determined to calculate the generation cost component of the residential tariff. Using the most recent data available, the contracting levels in 2023 served as the basis and the succeeding years are assumed to maintain a similar contracting profile throughout the forecast horizon.
- Baseload level is assumed to be the minimum average hourly contracted capacity for each region and is determined based on the 2023 contracting data.
- Peak contracts are assumed, so that the total contract level during peak hours is assumed to be at 80% of the total demand, consistent with the historical data from 2023.

- Spot purchases and contract differences determine the generation cost component of the retail electricity tariff. Contract prices are assumed to have a risk premium applied to the equivalent settlement price. In the context of electricity markets, the risk premium is the difference between the forward contract price and the expected spot price, often paid as compensation for bearing price or demand risks. Empirical studies across various electricity markets, including those in PJM, Germany, and Australia, suggest that generators incorporate a premium to account for spot market risks in energy-only markets, with these risk premiums ranging from 5% to as much as 14%. For the generation cost calculations, the average risk premium of 10% is applied.
- Aside from the generation cost, other components in the retail electricity tariff such as transmission, distribution, are assumed constant based on the 2023 average rates from MERALCO.
- To calculate the economic cost (in addition to user tariff levels), we have assumed a value of customer reliability of 64,000 Php/MWh, and loss of load expectation associated with the new entrant outlook to be 1 day a year.

Historical Load Profile

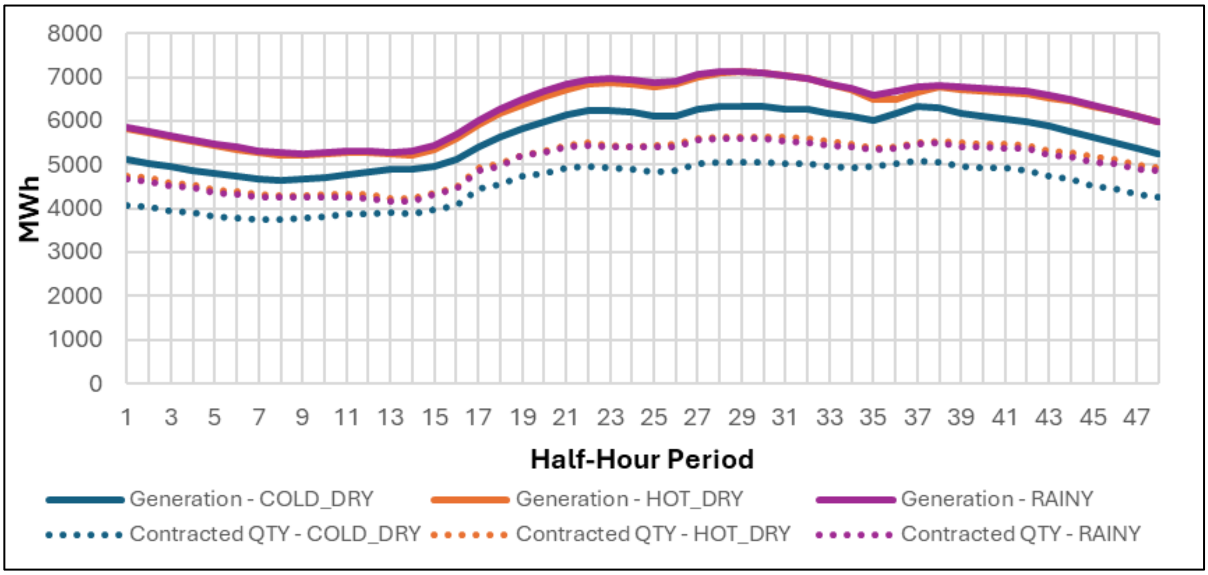
Figure 21 shows the historical spot market exposure for each season in 2022 and 2023. There was a 6.4% decrease in the total system contracting level from 2022 to 2023, with the 2023 level averaging 80% across all seasons. Moreover, Figure 22 illustrates the average half-hourly seasonal demand and contracting profiles, showing that on average, the contracted level is consistently around 80% of the total demand throughout the day. The average system-wide profile forms the basis of the retail load shape.

Figure 21 Total System Spot Market Exposure



	COLD_DRY 2022	COLD_DRY 2023	HOT_DRY 2022	HOT_DRY 2023	RAINY 2022	RAINY 2023
SPOT QTY	12.28	19.73	13.68	18.73	13.74	20.38
CONTRACTED QTY	87.72	80.27	86.32	81.27	86.26	79.62

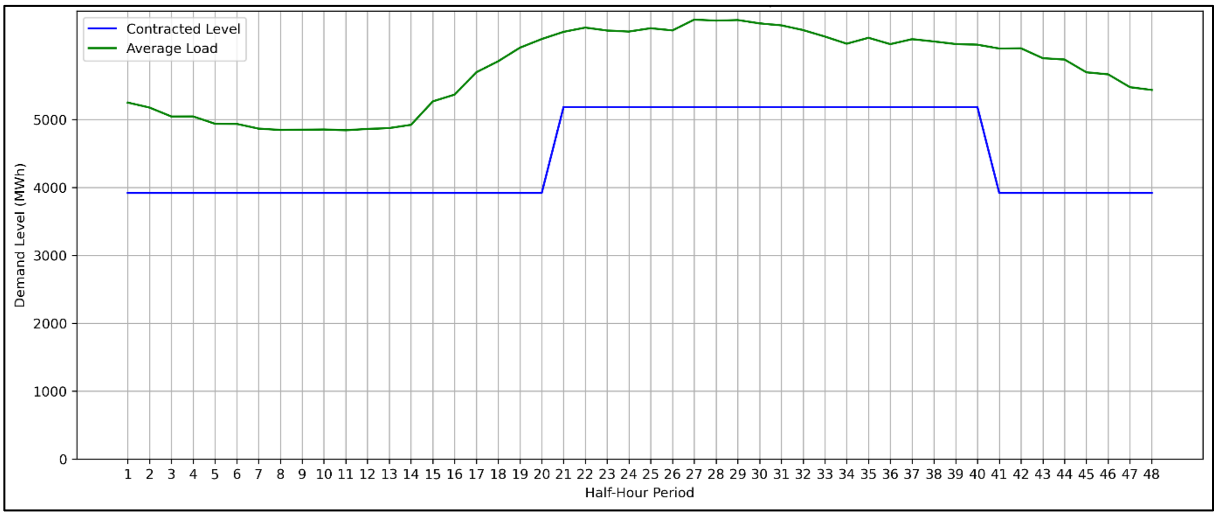
Figure 22 Average Half-Hourly Seasonal Demand and Contracted Levels (2023)



Contract Level Assumptions

From the reference profile, the peak hours are assumed to be from market hours 11-20 (10:00am – 8:00pm). Based on the findings from historical contracts, the baseload contract level is assumed to be 80% of minimum demand, while peak load contracts are assumed to cover 80% of peak demand. Figure 23 illustrates the assumed contracting level to compute for the generation cost component of the residential tariff.

Figure 23 Contract Level Assumption



Tariff Components

The residential tariff comprises of various components aside from the generation cost. However, due to data limitations, the tariff model assumes that only the generation cost is directly affected by the changes in the market price settings. Table 9 presents the components considered in the tariff model, with values obtained from the breakdown of electricity charges from MERALCO averaged for year 2023.

Table 9 Residential Tariff Components

Component	Cost	Description/Basis
Generation Charge	Annual Average	Computed from the PROPHET Outputs
Transmission Charge*	0.680 Php/kWh	Changes every month based on the movement in transmission cost.
System Loss*	0.613 Php/kWh	Changes every month based on the movement in generation and transmission costs and 12-month moving average system loss.
Distribution Charge*	0.9803 Php/kWh	Distribution, Supply, and Metering Rates in accordance with the Decision in ERC Case No. 2015-112 RC dated June 16, 2022.
Metering Charge*	0.4979 Php/kWh	
Supply Charge*	0.335 Php/kWh	
FIT-All Renewables	0.0 Php/kWh	Collection suspended in 2023.
Universal Charge*	0.2437 Php/kWh	Based on ERC guidelines

**Based on Meralco's 2023 residential tariff and is assumed to be constant throughout the forecast horizon.*

5.9 Key WESM Arrangements

Must-run Generators

Must-run status is given to generators with intermittent renewable energy generation. This includes solar and wind. This is incorporated in the PROPHET model for solar and wind generators.

Preferential Dispatch Generators

With the recent changes introduced in the market rules, the qualified renewable energy generators can decide to be classified as priority/preferential dispatch generators. Under this classification, the generator offers its entire available capacity and dispatched without regard to the market prices. Generators qualified to apply for this status include geothermal, biomass and hydroelectric plants. This is considered in the PROPHET model through generator bids by setting the price offers at the market price floor to simulate the market dynamics of having specific technologies under this status.

Feed-in Tariff (FIT)

This refers to the out-of-market settlement given to qualified renewable energy plants such as solar, wind and run-of-river hydroelectric power plants to incentivise investments and accelerate development of RE sources. This protects the generators from the price volatility of the spot market and ensures revenues for the generators in the long run. The feed-in tariff is currently passed on to consumers however, the collection is currently suspended. This is currently not considered in the PROPHET Model and all VRE are assumed to derived revenues either from the spot market and/or bilateral contracts which is what would be expected in a competitive energy market without policy support.

6 Modelling Results

The modelling results are presented in this section, beginning with a discussion of the outcomes from the base model, developed using the backcasting process. Scenario 1 (S1) presents the supply outlook required to meet the demand-supply balance and evaluates the pricing outcomes, along with the impact of the current Primary Price Cap (PPC) and Secondary Price Cap (SPC) on revenues and cost recovery, particularly for new entrant generators. Scenario 2 (S2) builds on this analysis and focuses on the implications of the proposed higher SPC, changes to pricing outcomes and their effects on cost recovery.

Scenario 3 (S3) presents the results of a proposed optimal PPC while the proposed amendment SPC is maintained, demonstrating the improvement on cost recovery compared to the outcomes of S1 and S2. The analysis highlights why the proposed PPC offers more favourable implications for revenues and cost recovery, particularly for new entrant generators, when assessed against the previous scenarios.

6.1 Backcasting Results

The backcasting process ensures that the model database is calibrated against historical outcomes, improving the accuracy and credibility of projections. Key assumptions, such as generator bidding behaviour and plant outages, are refined to reflect actual market dynamics, ensuring that the modelled outcomes align closely with historical trends.

The backcasting results, as shown in Figure 24, Figure 25 and Figure 26 highlight that regional energy prices, capped at Php32,000/MWh, align closely with historical price duration curves at lower price levels. A Price Duration Curve shows the distribution of prices over a specified period (% of time of the year in this case), showing how frequently prices exceed certain levels, helping to analyse price volatility and identify periods of high or low pricing. Within these curves, the top and bottom sections are identified as the most critical areas for focus, as they represent periods of extreme market prices that significantly influence revenue projections. The absence of network constraints in the model limits its ability to fully capture the historical price peaks and volatility. However, it still replicates the general pricing dynamics and volatility.[9] As a result, annual modelled prices are estimated to be 8% and 15% lower than actuals for Luzon and Visayas, respectively, while prices for Mindanao are 7% higher. These outcomes provide a cautious baseline, avoiding overestimation of generator revenues.

[9] The purpose of the backcast is to replicate the general pricing and generation dynamics within an acceptable margin of error, while acknowledging any potential biases when interpreting results and drawing conclusions.

Figure 24 **Luzon 2023 price duration curve vs Backcast (real, 2023 Php)**

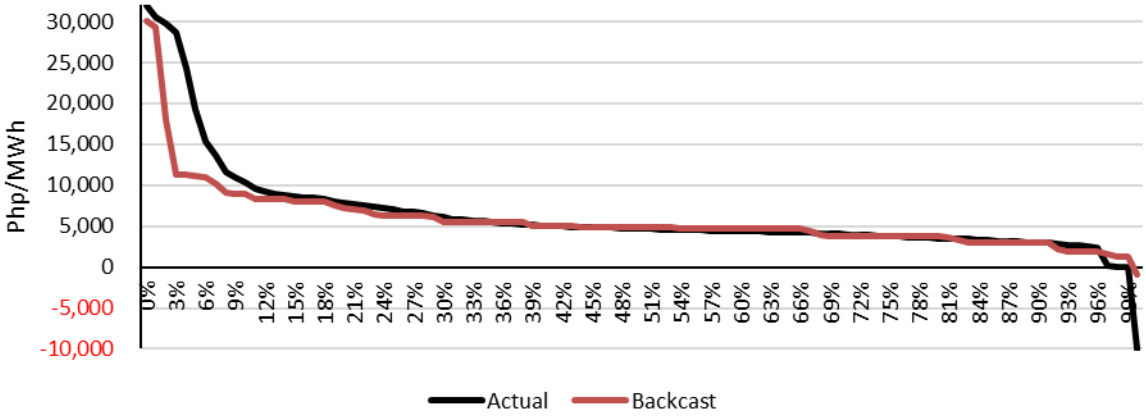


Figure 25 **Mindanao 2023 price duration curve vs Backcast (real 2023 Php)**

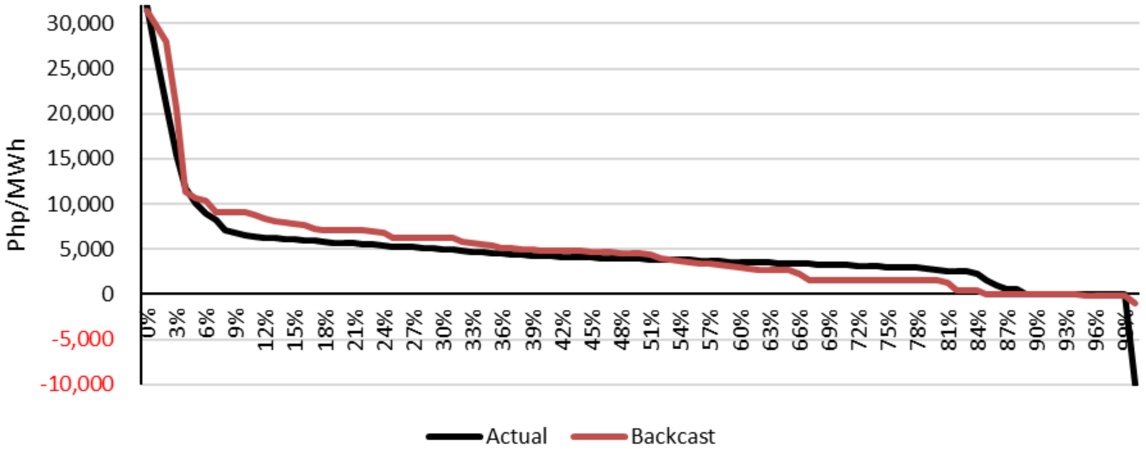
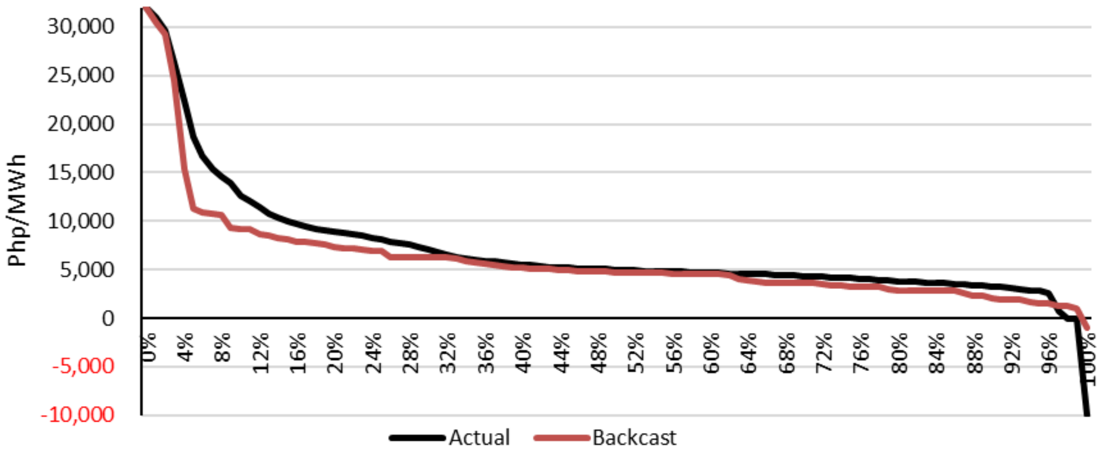
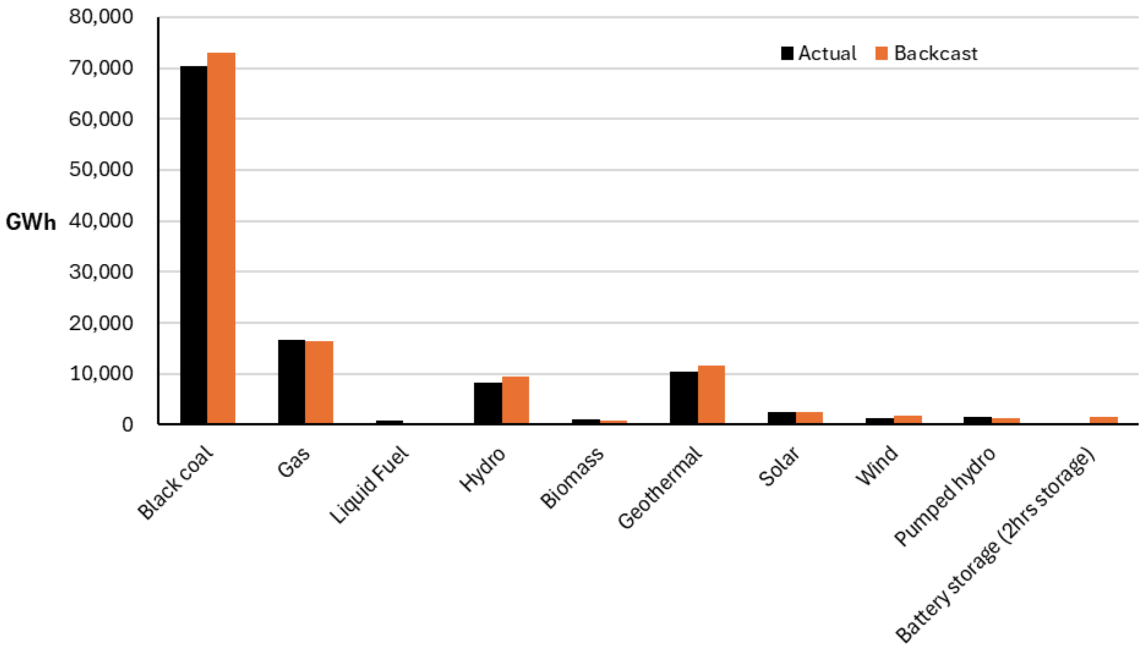


Figure 26 **Visayas 2023 price duration curve vs Backcast (real 2023 Php)**



In addition to pricing outcomes, ensuring accurate generation levels is equally important for maintaining the reliability of the model. Annual generation by fuel source is calibrated at the system level (see Figure 27 below) and, where possible, within regions. Fuel-specific generation patterns are adjusted to align with historical data, maintaining deviations within 10%, or 5% for fuels with a higher generation share, such as coal. This detailed calibration ensures that the modelled generation patterns are consistent with historical performance and supports the overall credibility of the model's outputs.

Figure 27 System-wide generation volumes in 2023 vs Backcast



6.2 Project Supply and Demand Outlook

This section presents the transitioning energy mix to meet future demand, highlighting changes in capacity composition, the growing role of new entrant technologies and the generation mix.

The capacity mix, as presented in Figure 28, underscores the transition, with a substantial portion of new capacity additions attributed to renewable and flexible technologies. By 2030, as shown in Figure 29, new entrants account for 72% of solar, 85% of wind, 57% of pumped hydro, and 74% of battery storage capacity, showcasing the system's growing reliance on cleaner and more adaptable energy sources. In contrast, conventional technologies like black coal and CCGTs retain a larger share of existing capacity, ensuring system reliability as the energy transition progresses.

Figure 28 Capacity share as system level by fuel and status

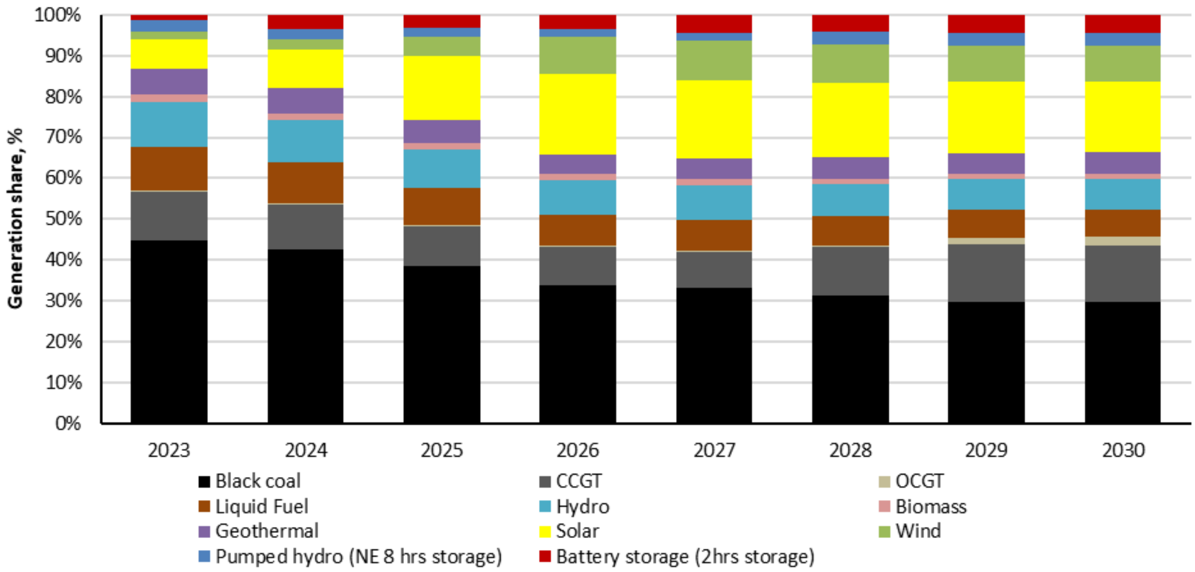
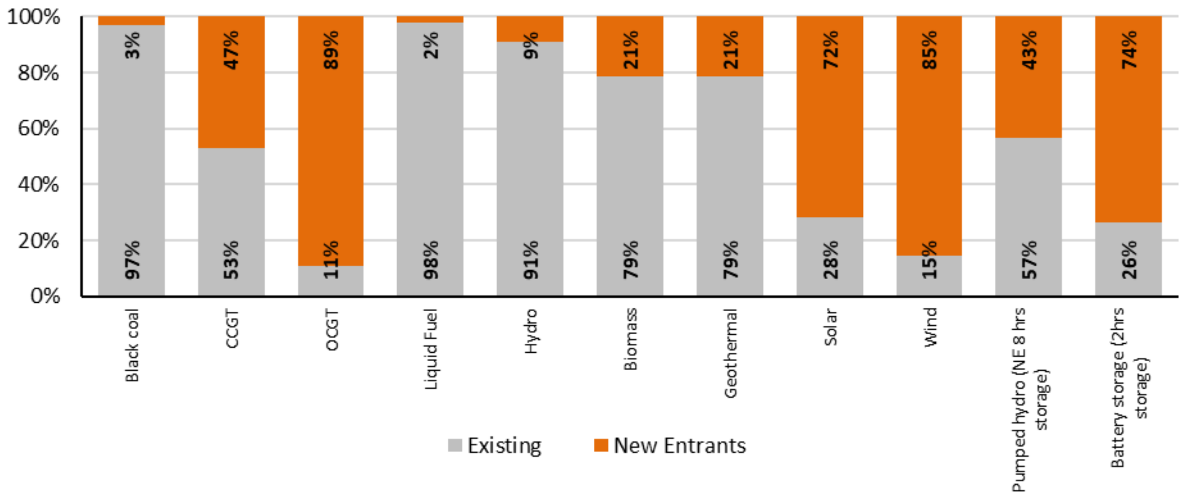


Figure 29 New entrant share of capacity mix by 2030

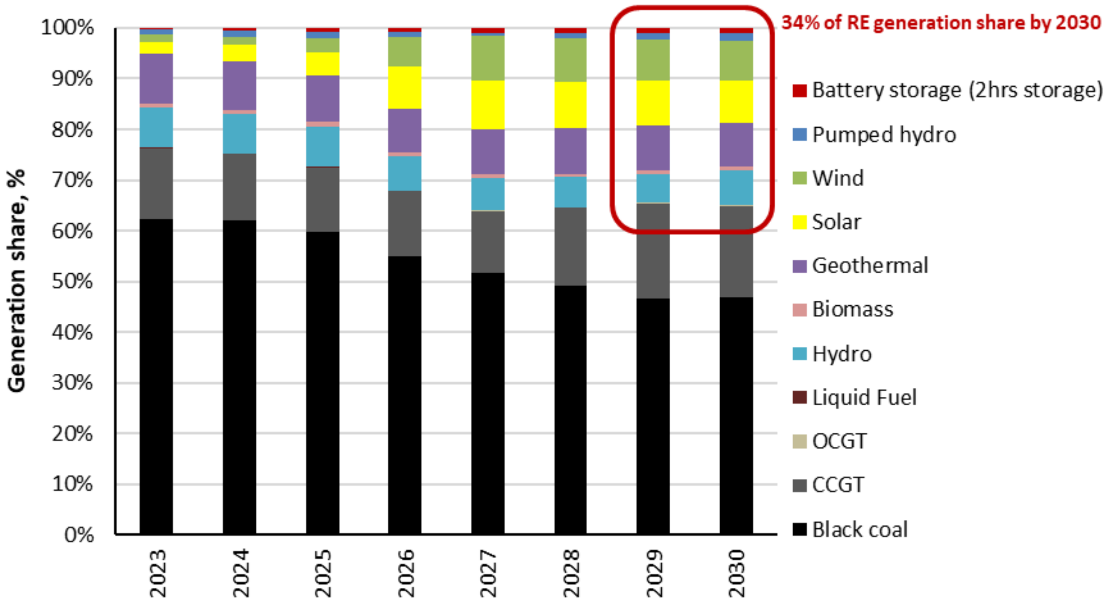


This system balances reliability provided by baseload and intermediate technologies with the flexibility offered by renewables and peaking solutions. The increasing contribution of new entrant technologies highlights the shift toward sustainability while securing the reliability and strength needed for future energy requirements.

The generation share outlook, as shown in Figure 30, further reflects a balanced transition, with conventional technologies maintaining reliability while renewable energy (RE) sources and flexible solutions increase their contributions.

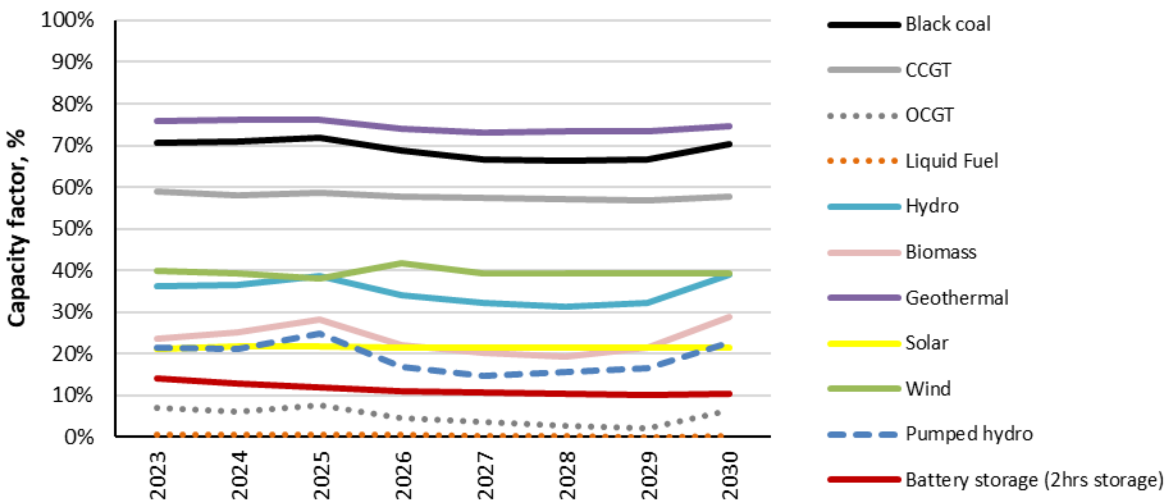
The generation mix shows that black coal remains a significant contributor in the near term, providing reliable baseload supply. By 2030, RE sources, including solar, wind, hydro, and biomass, account for 34% of annual generation. This is very close to meeting the RE objective of 35% share in the energy mix by 2030. Solar and wind, as VRE sources, demonstrate steady growth, supported by storage technologies that maintain grid stability and facilitate their integration.

Figure 30 Annual generation share by fuel type 2023-2030



The roles of these technologies are further illustrated by their capacity factors in Figure 31. Baseload sources, such as black coal and geothermal, achieve high utilisation rates of 69% and 74%, respectively. Intermediate technologies including CCGTs and hydro follow with 58% and 32% capacity factors. Solar and wind, with capacity factors of 19% and 35%, respectively, contribute a fair share to the mix without curtailment. Peaking technologies, such as batteries (10%), pumped hydro (17%), and OCGTs (5%), exhibit lower utilisation rates, reflecting their role in supporting VRE during peak periods and ensuring grid stability.

Figure 31 Utilisation rates by fuel type 2023-2030



6.3 Projected Spot Prices and Volatility

6.3.1 Spot prices

Figure 32 to Figure 37 below illustrate the price trends from 2023 to 2030, covering both the backcast and forecast periods for each region, along with price duration curves for 2030. They compare Scenario 1 (current SPC), Scenario 2 (amended SPC with a higher cap), and Scenario 3 (increased PPC to optimal while SPC remains unchanged), highlighting the implications of these changes on price outcomes and revenue generation.

Figure 32 Luzon price outlook 2023-2030 (real 2023 Php)

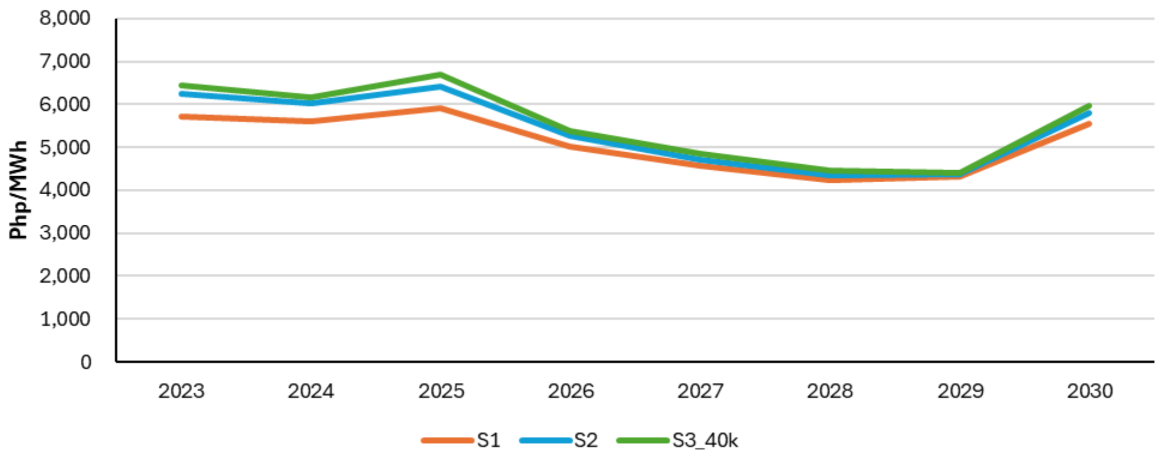
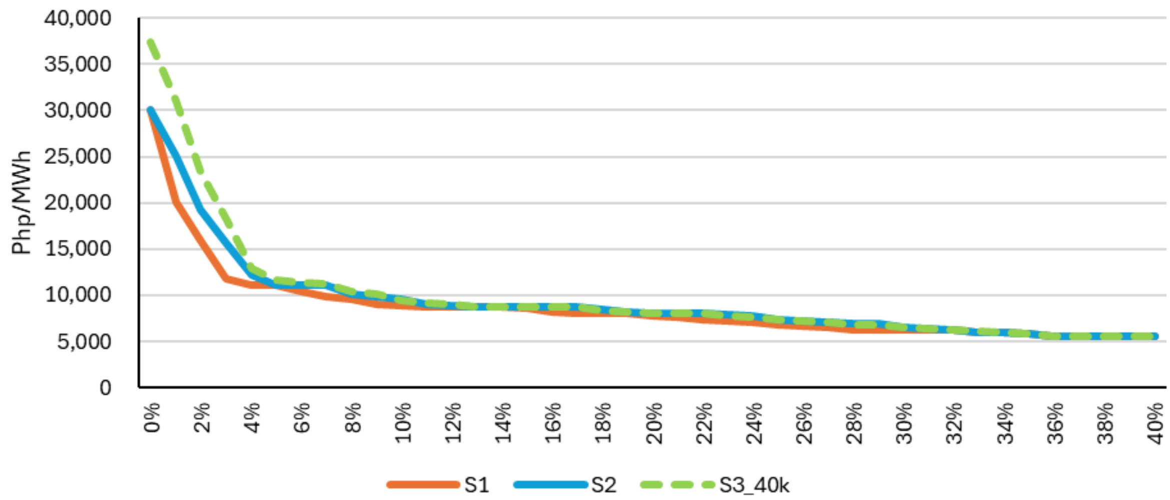


Figure 33 Luzon 2030 price duration curve (real 2023 Php)



The increase in RE capacity in Luzon by 2026 results in lower electricity prices across all regions in all scenarios. This reduction is further supported by transmission upgrades, which enable excess generation in Luzon to be transferred to Visayas and Mindanao, improving supply distribution and reducing regional price disparities. By 2027, transmission augmentations[10]

[10] Transmission Development Plan (2024-2050) - National Grid Corporation of the Philippines

brought forward to address network congestion, lead to price convergence across regions, with alignment continuing through 2030.

Figure 34 Mindanao price outlook 2023-2030 (real 2023 Php)

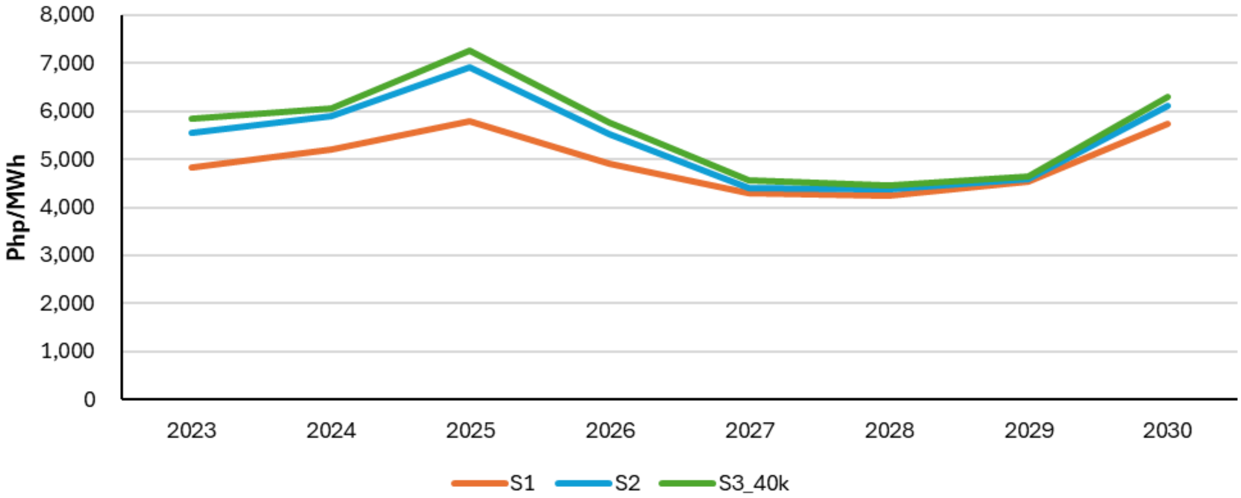


Figure 35 Mindanao 2030 price duration curve (real 2023 Php)

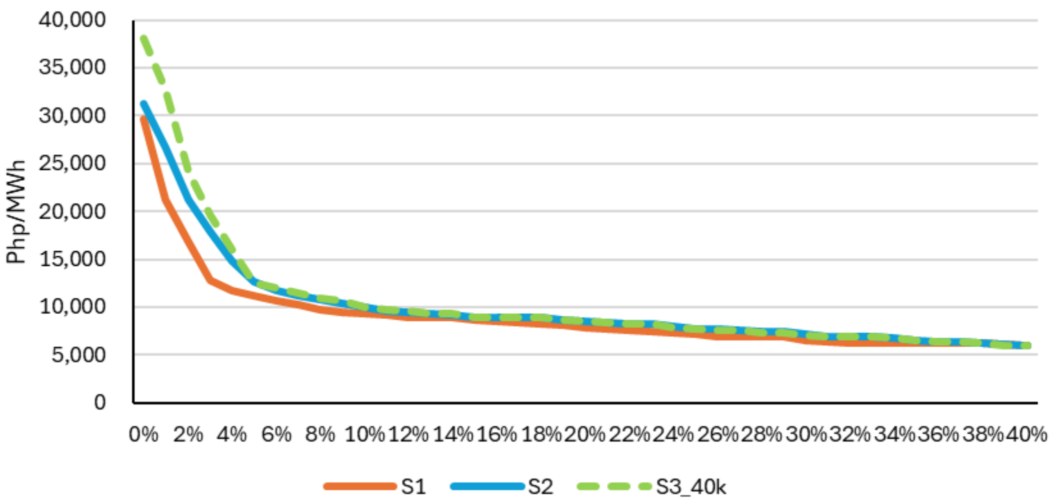


Figure 36 Visayas price outlook 2023-2030 (real 2023 Php)

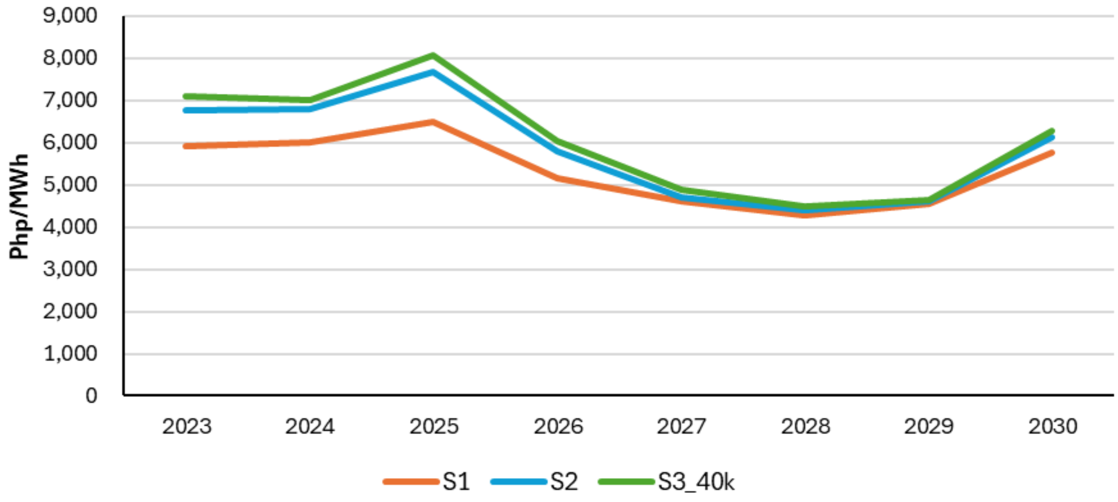
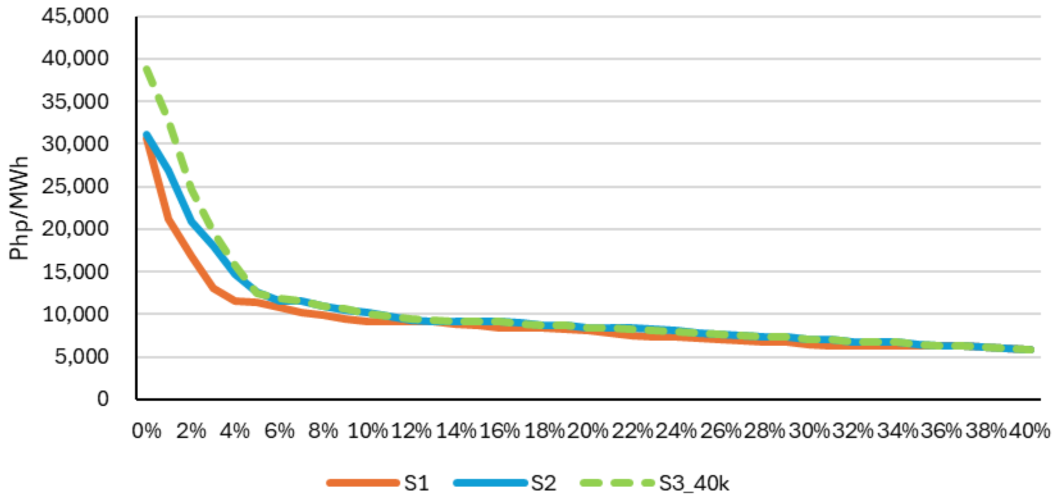


Figure 37 Visayas 2030 price duration curve (real 2023 Php)



The higher SPC (increased to 9,852.6 Php/MWh under the CPT period of 7 days and CPT threshold at 13,657.38 Php/MWh) in Scenario 2 allows for additional volatility and higher price signals for new capacity. This creates improved opportunities for revenue recovery, and in particular for peaking plants, which benefit from the higher SPC.

Scenario 3 retains the amended SPC but introduces an increased PPC raised to Php 40,000/MWh. This price reflects the recommended price mitigation measure for the Philippines WESM, to ensure adequate revenue for new entrant plant across a single system portfolio and as such, to incentivise market entry and support power system reliability. This is determined through spot market price analysis and modelling iterations. The higher PPC leads to greater price variability, with the price charts highlighting increased volatility from increasing PPC. The implications of this optimal PPC are further discussed in subsequent sections.

6.3.2 Volatility

PPC intervals

The following charts illustrate the frequency of market prices exceeding Php 10,000/MWh in each region from 2023 to 2030, indicating the difference in volatility across the scenarios. Under Scenario 2, the increased SPC allows for a higher cumulative price threshold, allowing greater volatility and frequency of prices exceeding Php 10,000/MWh. Scenario 3, with a higher PPC, shows a slightly higher volatility than Scenario 2.

The higher PPC creates more pronounced price signals, allowing peaking plants and generators to recover costs more effectively during periods of extreme demand. Despite these adjustments, the percentage of intervals reaching the actual PPC across regions remains between 0% and under 1% throughout the forecast term. This aligns with trends observed in the Australian NEM, where only 0.1% of intervals between 2022 and 2024 reached the PPC.

Based on the analysis, the amended SPC as modelled in Scenario 2 has a higher impact to volatility than the change in amended SPC and PPC in Scenario 3. Conversely, the modelling also shows the degree of volatility that is suppressed under the current SPC arrangement.

Figure 38 Frequency of regional prices exceeding Php 10,000/MWh - Luzon

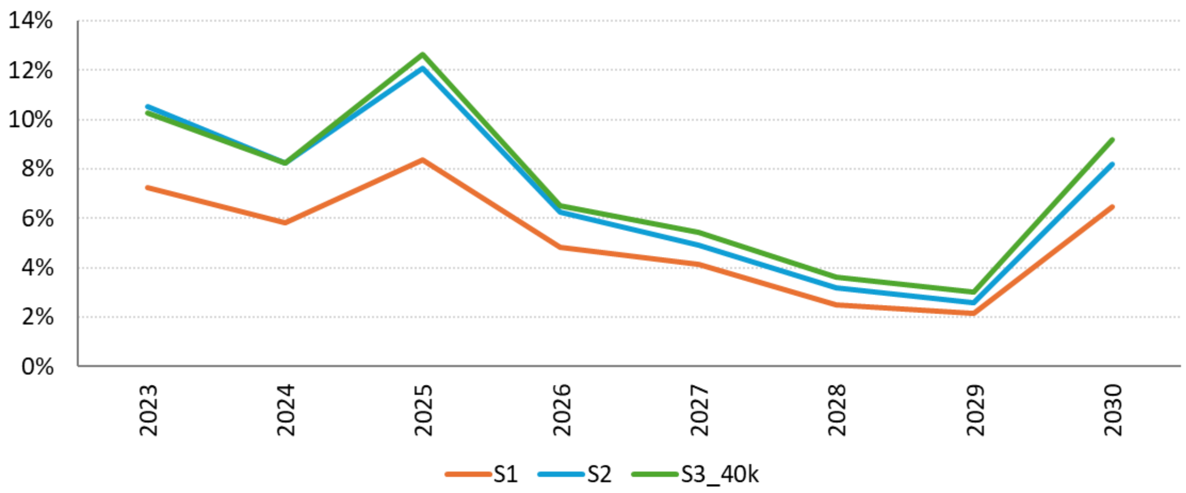


Figure 39 Frequency of regional prices exceeding Php 10,000/MWh - Mindanao

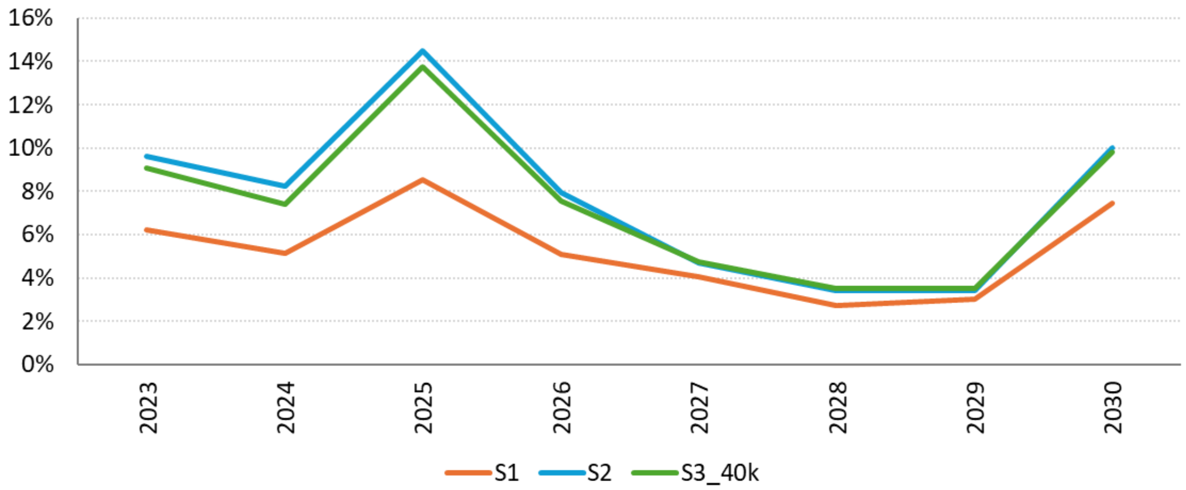
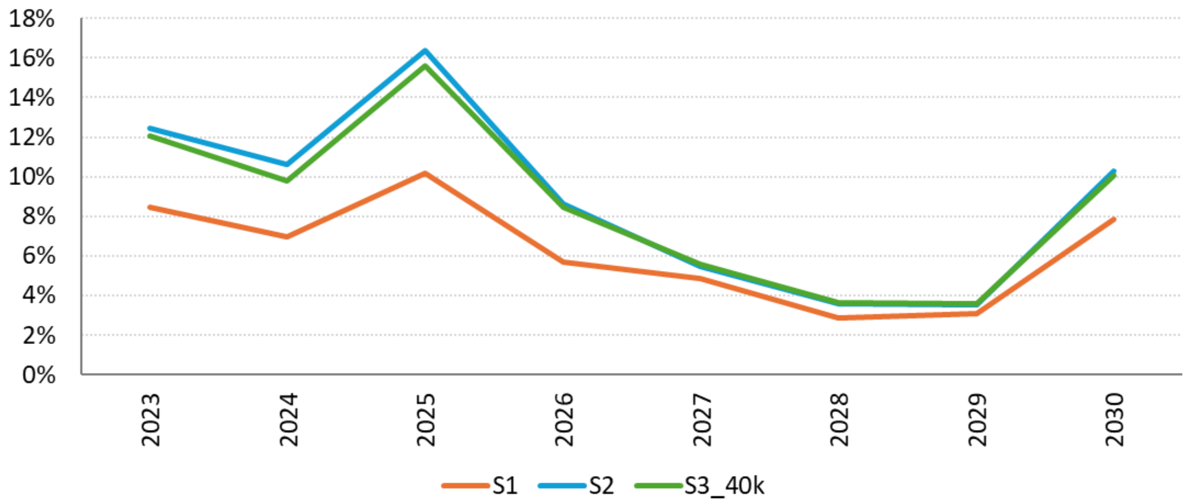


Figure 40 Frequency of regional prices exceeding Php 10,000/MWh - Visayas



SPC intervals

Active SPC Intervals refers to the number of intervals during a year when the SPC is active due to high market prices triggering the cumulative price threshold, triggering price controls to manage market volatility. The charts below, Figure 41, Figure 42, and Figure 43 illustrate the percentage of active SPC intervals over the forecast period, comparing the impacts of the current SPC in Scenario 1 (S1), the amended SPC in Scenario 2 (S2), and the higher PPC in Scenario 3 (S3). The extent to which SPC triggers helps highlight how changes to the SPC and PPC thresholds influence price dynamics, market behaviour, and cost recovery for generators.

Early in the forecast period in Scenario 1, tighter supply-demand conditions in Luzon drive frequent SPC active intervals due to increased price volatility. However, as capacity expands with renewable energy integration and generation adequacy improves, prices remain high but less volatile, leading to a further decline in SPC active intervals by 2030. The average active SPC intervals between 2025 and 2030 across all regions is 4.5%.

In Scenario 2, the amended SPC raises the price threshold, reducing the frequency of active SPC intervals. By limiting the number of intervals when the SPC is active, the amended threshold prevents the dampening of market price signals and improves cost recovery opportunities for generators. For the period 2025-2030, the average active SPC across all regions is reduced to 0.4%. Note that by limiting the SPC's active intervals to fewer instances, this allows for better cost recovery for generator. As a comparison the equivalent active SPC intervals in the Australia NEM is close to zero over the past 20 years.

Figure 41 Frequency of SPC active intervals at Luzon 2023-2030

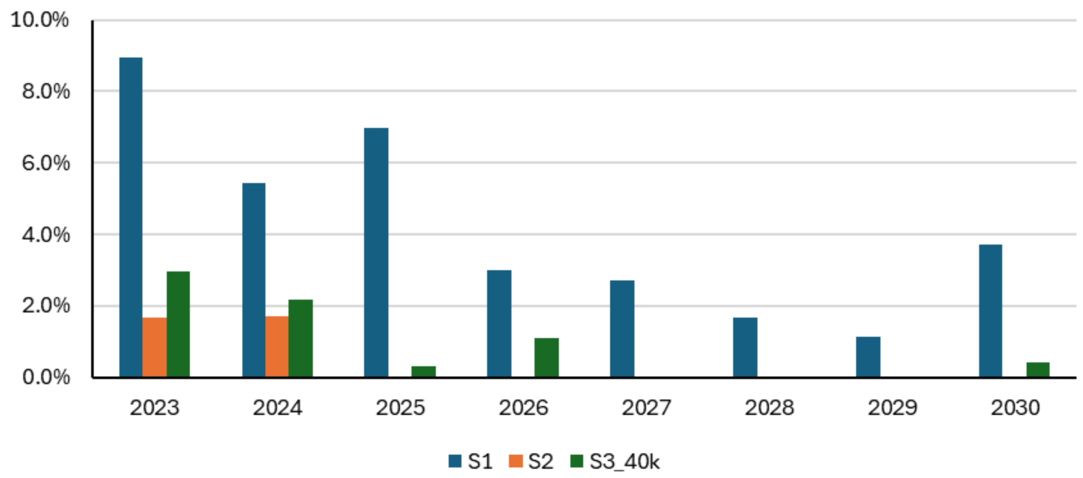


Figure 42 Frequency of SPC active intervals at Mindanao 2023-2030

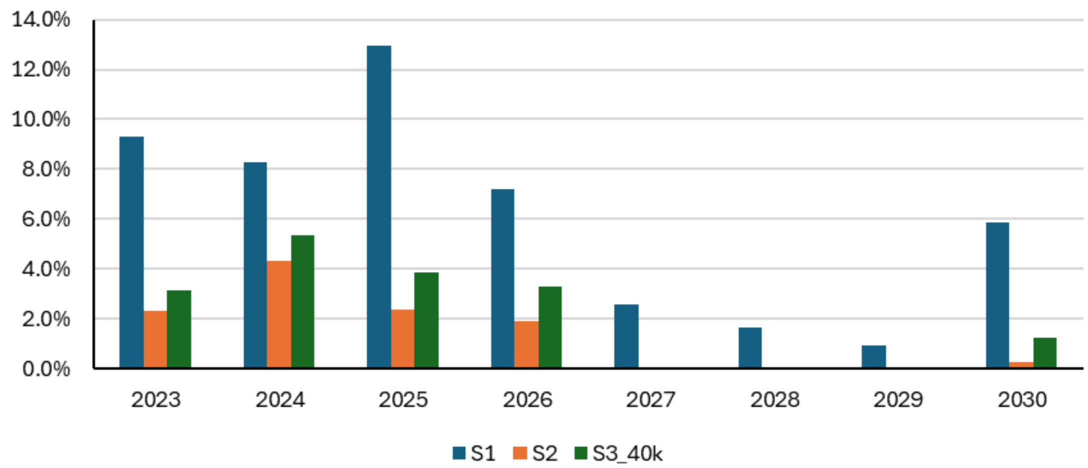
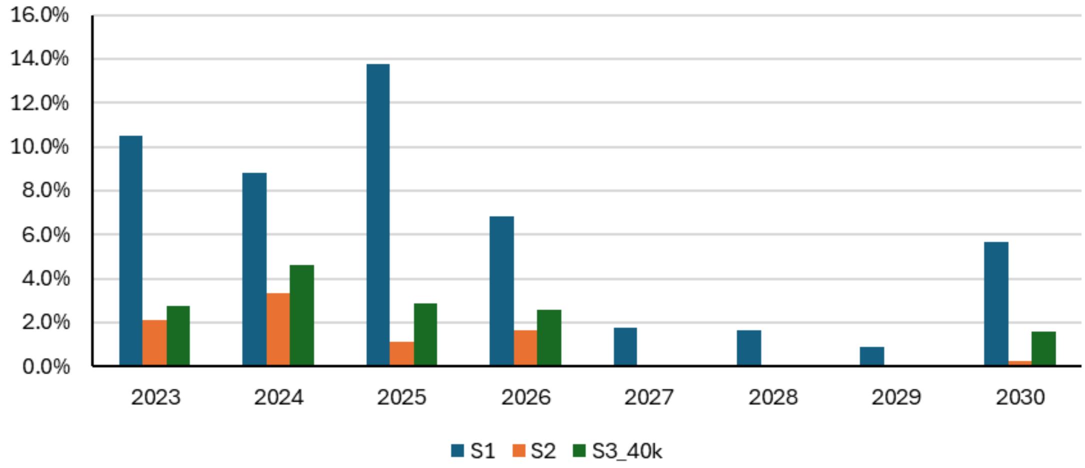


Figure 43 Frequency of SPC active intervals at Visayas 2023-2030



Scenario 3 introduces a higher PPC while retaining the amended SPC, which leads to an increase in the percentage of active SPC intervals compared to S2 (average 2.3% from 2025-2030 across all regions).

The results above illustrate how changes to the SPC and PPC thresholds can balance price volatility with cost recovery, ensuring a more efficient and reliable market structure. By raising both thresholds, price volatility is increased, providing critical price signals necessary for supporting market adaptability and system reliability. These improvements help maintain the necessary price signals to support investment in flexible capacity and enable peaking technologies and generators to recover costs during periods of extreme demand.

6.4 Revenue Impacts

The impact of the price settings across the established scenarios are assessed in alignment with the project's goal of enhancing the spot market and attracting investments in renewable energy. A view on spot and contract revenues provides insights on how the price settings influence the financial viability of new entrant generators as well as the overall market dynamics, highlighting investment opportunities and potential areas for policy refinement.

6.4.1 Spot Revenues by Plant Type

Spot revenues are assessed for each plant type to determine how they perform under different price settings in the spot market. Spot revenues by plant type across the three scenarios are calculated and summarised in Table 10.

The impact of the revised price settings in the spot market revenues for each new-entrant plant type throughout the forecast horizon is presented in Table 10 and the movement of revenues using scenario 1 as baseline is shown in Table **11**. To support the uptake of renewable energy in the generation mix, price settings should not only incentivise investments in renewable energy generators but also support the development of firming generation technologies, such as battery energy storage systems, peaking gas plants, and pumped storage. With the amended secondary price cap and optimal primary price cap set at 40,000 Php/MWh (Scenario 3), the average spot revenues for VRE are only at a relatively lower levels compared to other technologies. VRE revenues increased by up to 6% in Scenario 3, compared to at most 4% increase in Scenario 2. Furthermore, Scenario 3 shows that under the updated PPC and SPC, spot revenues increase significantly for batteries, peaking plants, and pumped storage. This underscores both their reliance on higher price caps to recover costs and their crucial role in firming VRE generation.

Table 10 Spot Revenues in Millions Php per MW Capacity Installed

Scenario	Plant Type	2025	2026	2027	2028	2029	2030	Average
S1	Battery (Gen-Load)	2.71	2.56	2.22	1.66	1.43	1.99	2.10
	Biomass	17.83	13.77	16.15	13.97	15.78	22.68	16.70
	CCGT	-	26.46	23.89	21.24	21.11	27.85	20.09
	Coal	-	15.13	23.22	24.17	25.11	32.44	20.01
	Liquid Fuel	0.63	1.05	0.19	0.11	0.01	0.20	0.36
	Geothermal	20.94	29.47	23.70	26.21	27.04	34.67	27.01
	Hydro	22.39	23.39	15.45	13.96	14.68	20.34	18.37
	OCGT	-	-	-	-	1.81	5.47	1.21
	Pumped Hydro	-	-	-	7.03	10.38	12.54	4.99
	Solar	4.02	5.54	5.86	5.92	6.36	8.38	6.01
	Wind	9.56	9.13	12.46	12.14	12.49	16.54	12.05
S2	Battery (Gen-Load)	3.64	3.04	2.38	1.80	1.48	2.25	2.43
	Biomass	22.64	15.69	16.79	14.58	16.09	24.62	18.40
	CCGT	-	28.30	24.88	22.07	21.35	29.16	20.96
	Coal	-	16.14	23.74	25.09	25.57	34.71	20.88
	Liquid Fuel	1.33	2.09	0.32	0.28	0.02	0.40	0.74
	Geothermal	24.35	32.42	24.43	27.04	27.38	36.33	28.66
	Hydro	27.31	26.61	16.29	14.80	15.02	21.89	20.32
	OCGT	-	-	-	-	2.03	7.04	1.51
	Pumped Hydro	-	-	-	7.25	10.52	13.35	5.19
	Solar	4.41	5.90	5.96	6.04	6.42	8.71	6.24
	Wind	10.24	9.57	12.70	12.39	12.57	17.06	12.42
S3	Battery (Gen-Load)	3.98	3.34	2.66	2.02	1.52	2.46	2.66
	Biomass	24.16	16.63	17.62	15.06	16.33	25.48	19.22
	CCGT	-	29.14	25.76	22.67	21.54	30.10	21.54
	Coal	-	16.94	24.54	25.84	25.84	35.75	21.48
	Liquid Fuel	1.36	2.30	0.37	0.38	0.03	0.43	0.81
	Geothermal	25.48	33.70	25.16	27.65	27.61	37.42	29.50
	Hydro	28.79	27.80	17.20	15.43	15.31	22.91	21.24
	OCGT	-	-	-	-	2.22	7.91	1.69
	Pumped Hydro	-	-	-	6.79	10.80	14.74	5.39
	Solar	4.57	5.96	5.99	6.07	6.41	8.78	6.30
	Wind	10.53	9.80	12.95	12.59	12.64	17.46	12.66

Table 11 Increase in Spot Revenues per Plant Type compared against S1

Scenario	Plant Type	2025	2026	2027	2028	2029	2030	Average
S2	Battery	34%	18%	7%	8%	3%	13%	14%
	Biomass	27%	14%	4%	4%	2%	9%	10%
	CCGT	0%	7%	4%	4%	1%	5%	3%
	Coal	0%	7%	2%	4%	2%	7%	4%
	Liquid Fuel	111%	99%	69%	156%	151%	99%	114%
	Geothermal	16%	10%	3%	3%	1%	5%	6%
	Hydro	22%	14%	5%	6%	2%	8%	10%
	OCGT	0%	0%	0%	0%	12%	29%	7%
	Pumped Hydro	0%	0%	0%	3%	1%	6%	2%
	Solar	10%	7%	2%	2%	1%	4%	4%
	Wind	7%	5%	2%	2%	1%	3%	3%
S3	Battery	47%	30%	20%	22%	6%	23%	25%
	Biomass	36%	21%	9%	8%	4%	12%	15%
	CCGT	0%	10%	8%	7%	2%	8%	6%
	Coal	0%	12%	6%	7%	3%	10%	6%
	Liquid Fuel	115%	119%	97%	246%	303%	115%	166%
	Geothermal	22%	14%	6%	5%	2%	8%	10%
	Hydro	29%	19%	11%	11%	4%	13%	14%
	OCGT	0%	0%	0%	0%	22%	44%	11%
	Pumped Hydro	0%	0%	0%	-3%	4%	17%	3%
	Solar	14%	8%	2%	3%	1%	5%	5%
	Wind	10%	7%	4%	4%	1%	6%	5%

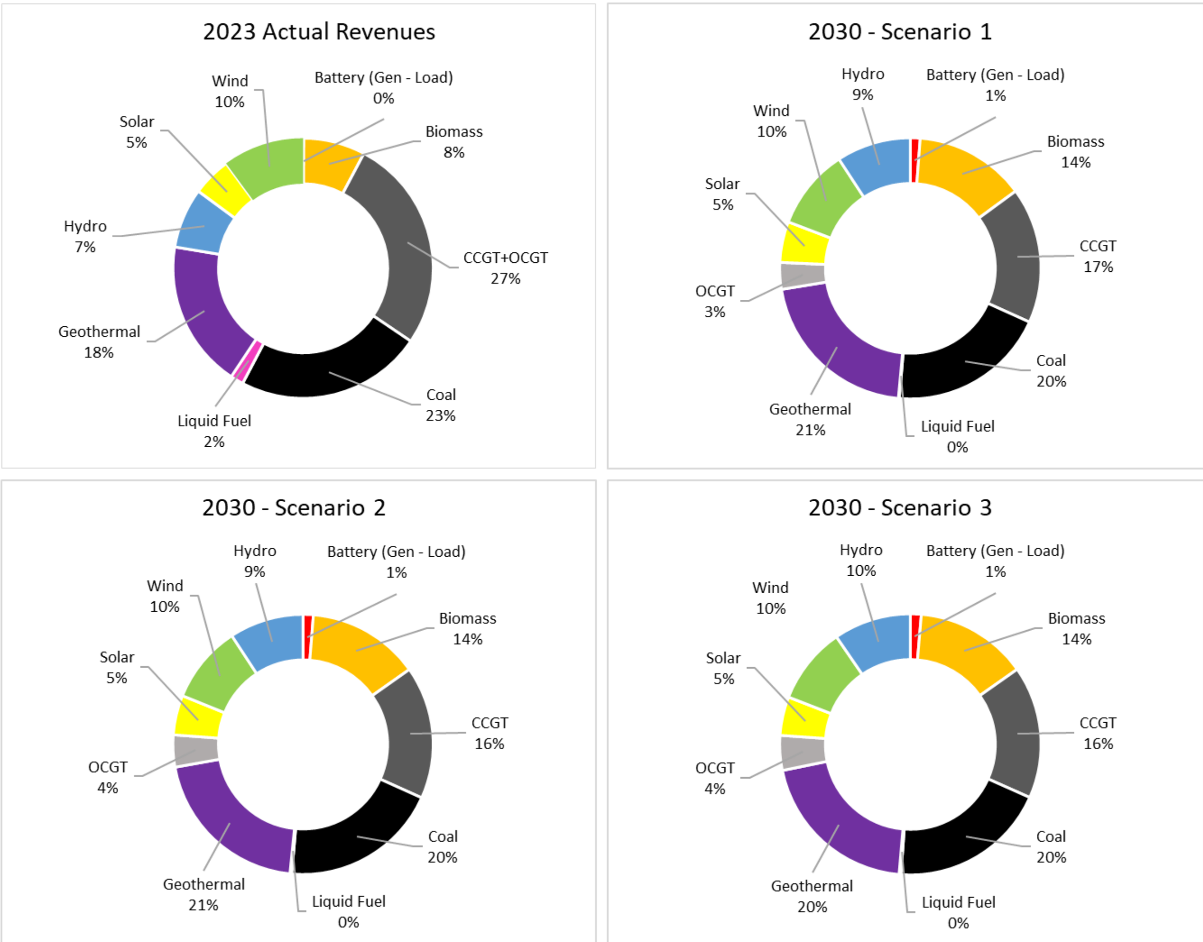
To provide a basis for assessing the impact of the updated price settings on revenues across the modelling scenarios, the 2023 historical spot revenues standardized per MW capacity are presented in Table 12 along with the revenue split across all scenarios in 2030. As seen in the comparison of gross spot revenues in Figure 44, there is a reduction in the share of coal in the gross spot revenues, reflecting the changes in the generation mix. In contrast, VRE and other renewable energies increased their share in the revenue split, highlighting the growing reliance on cleaner energy sources by 2030.

Table 12 Comparison of Gross Spot Revenues in Million Php per MW Capacity

Type	2023	2030		
		Scenario 1	Scenario 2	Scenario 3
Solar	5.37	8.38	8.71	8.78
Wind	11.25	16.54	17.06	17.46
Liquid Fuel	1.81	0.20	0.40	0.43
Biomass	8.55	22.68	24.62	25.48
Hydro	8.34	32.89	35.24	37.64
Geothermal	20.45	34.67	36.33	37.42
Coal	25.93	32.44	34.71	35.75
CCGT	29.84	27.85	29.16	30.10
Battery (Gen – Load)	0.10	1.99	2.25	2.46
OCGT	-	5.47	7.04	7.91

Note: 2023 Historical Gross Spot Revenues for CCGT and OCGT are combined as CCGT due to data limitations. Similarly, Hydro data includes the revenues for pumped storage hydro due to data limitations.

Figure 44 Gross Spot Revenue Comparison



6.4.2 Spot Revenue Composition Summary

Revenues related to the primary price cap (PPC) are determined to assess the impact of price settings on market dynamics and generator profitability. PPC-related and SPC-related revenues are calculated for market intervals with nodal prices exceeding the 10,000 Php/MWh threshold. Conversely, base revenue component refers to the portions generated at or below the 10,000 Php/MWh threshold. Figure **45** shows the contribution of the primary and secondary price caps to the total spot market revenues at the system level from 2025-2030 and Figure 46 shows the breakdown of the total spot revenues for each scenario. Compared to the base scenario (Scenario 1), maintaining the PPC at 32,000 Php/MWh while amending the SPC (Scenario 2) would see an increase in the total spot revenues by 4%. On the other hand, increasing the PPC together with the amended SPC (Scenario 3) would increase the total spot market revenues by 7%. These findings highlight that Scenario 3 could potentially enhance market incentives to generators while balancing price limits.

Figure 45 **Yearly Contribution of PPC and SPC on New Entrant Gross Spot Revenues**

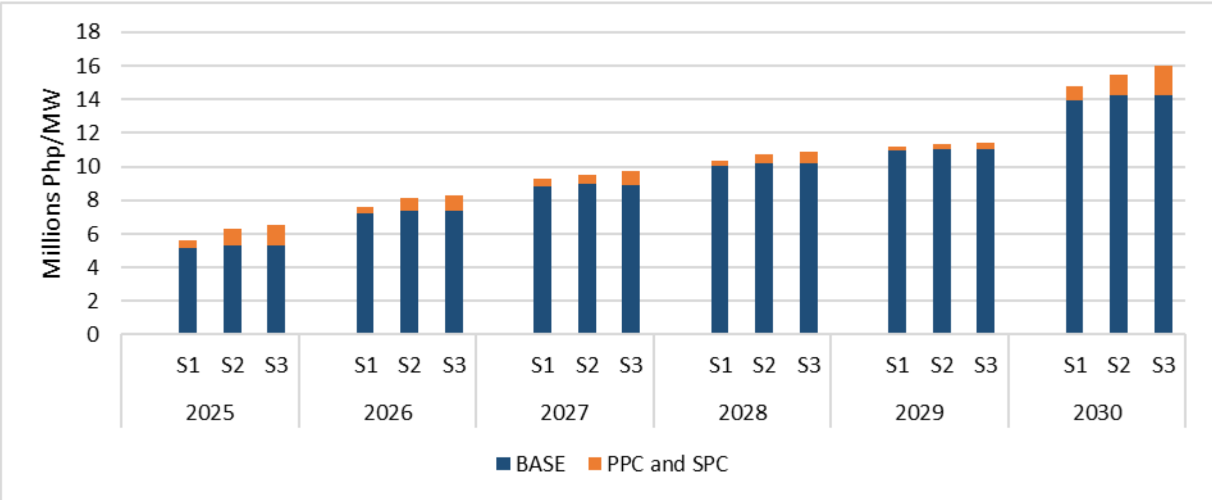
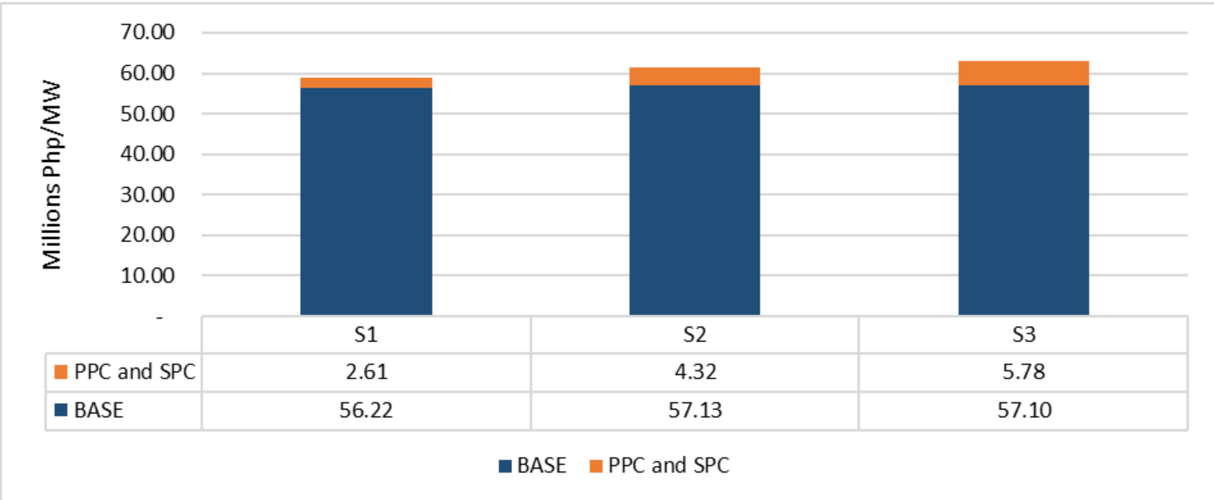


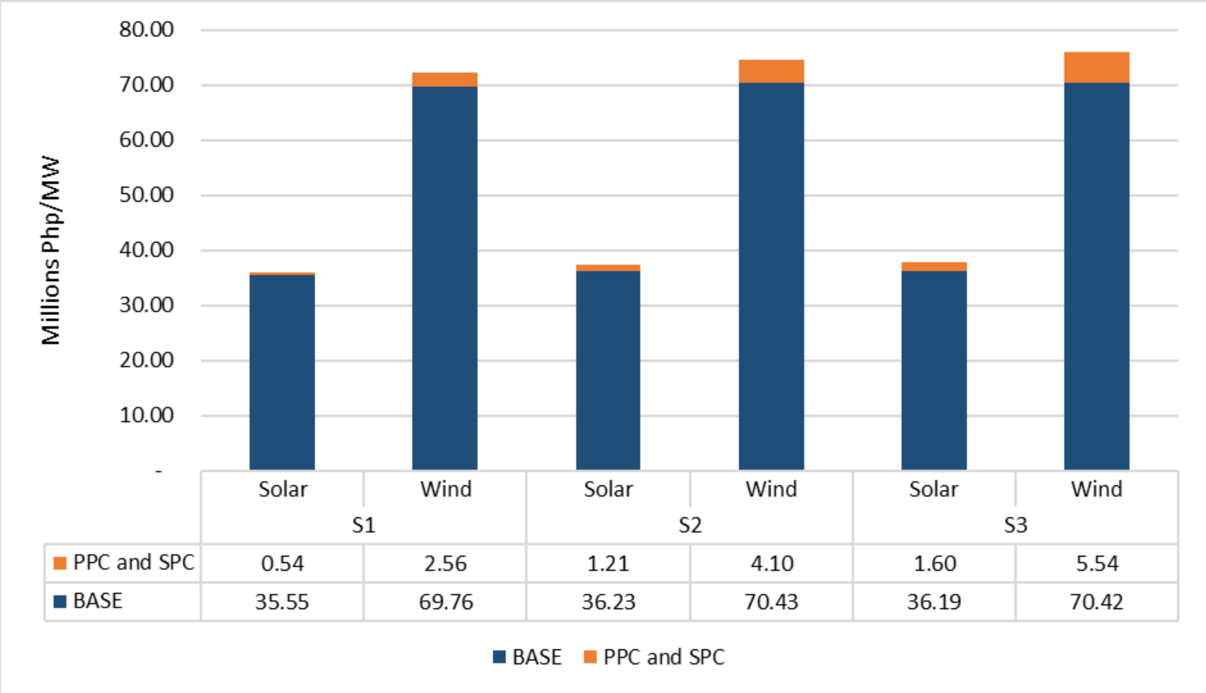
Figure 46 **Total Contribution of PPC and SPC on New Entrant Gross Spot Revenues**



	S1	S2	S3
PPC and SPC	2.61	4.32	5.78
BASE	56.22	57.13	57.10

The revenue split for VRE, illustrated in Figure 47, shows that changes to the PPC and SPC have minimal impact to the spot revenues of solar and wind. This is primarily due to their intermittent nature and their classification as priority dispatch generators in the market. As such, scaling the price cap alone cannot ensure revenue adequacy for these technologies. To achieve a greater share of renewable energy generation and overall grid reliability, it is equally necessary to build capacities for storage and peaking plants to compensate for periods when intermittent energy sources generate little to no power (e.g., no solar generation at night). Therefore, adjustments to the PPC and SPC are likely necessary to ensure cost recovery for storage and peaking plants.

Figure 47 Total Contribution of PPC and SPC on Spot Revenues for New Entrant VRE



6.4.3 Contract Revenues by Plant Type

Based on the historical contract levels, assumptions were made to calculate the contract revenue portion for each generator technology, as presented in Section 5.6. Figure 48 illustrates the spot and contract revenue breakdown generated by solar new entrants. The contract revenues account for the difference between the contract prices and spot market prices, providing stable generator revenues by smoothing out volatility. The contract price incorporates a 10% risk premium applied to the spot market prices. Consequently, the contract revenues scale with the movements in the primary price cap as illustrated in Figure 49.

Figure 48 Spot and Contract Revenues for New Entrant Solar

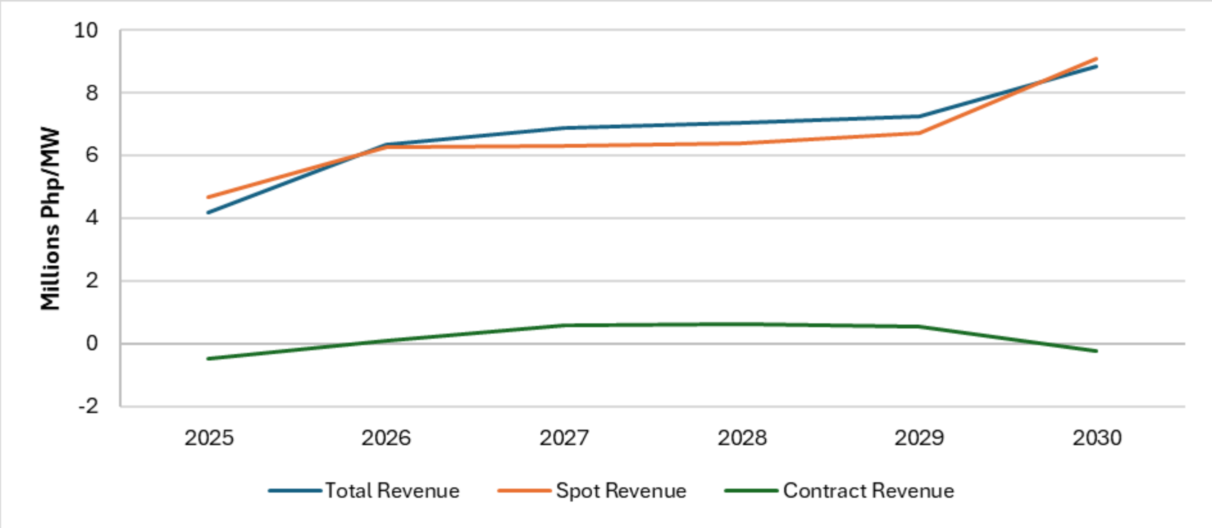
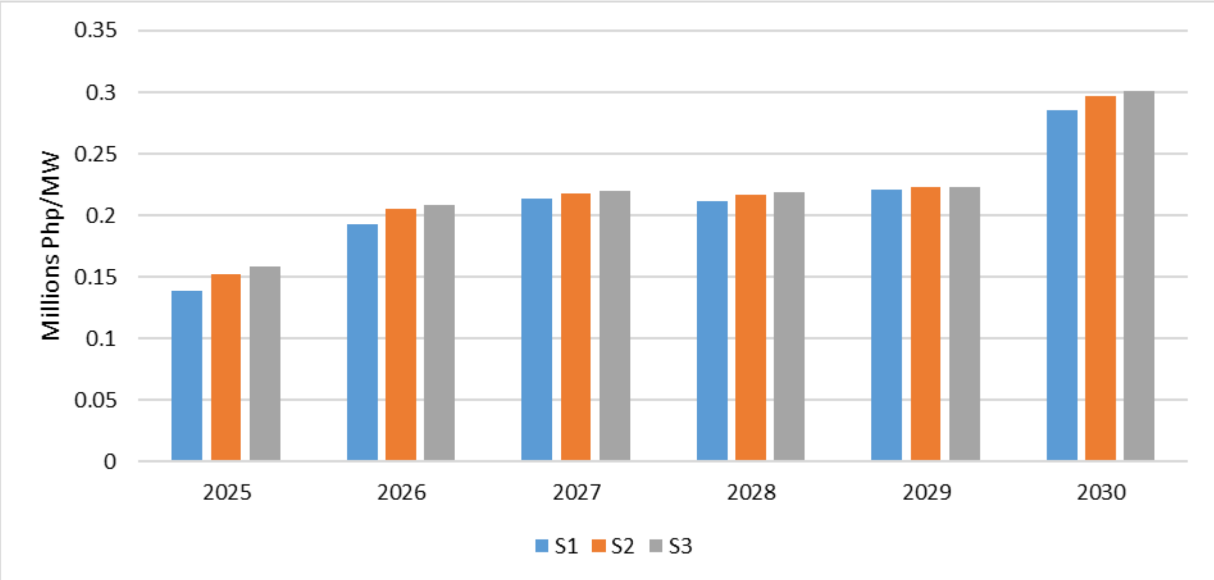


Figure 49 Contract Revenues for New Entrant Solar (in Million Php / MW)



The new entrant contract revenues for each generator technology, standardised per MW of installed capacity, are presented in Table 13. New entrant geothermal, CCGTs, and coal-fired plants derive a significant portion of their total revenues coming from contract difference payments, averaging from 1 to 2 million Php/MW from 2025-2030. Beginning 2029, OCGTs and CCGTs are seen to have the highest contract revenues per MW of installed capacity, as new entrants come online and as these technologies hold the highest contracting levels based on historical 2023 data. In contrast, new entrant batteries, pumped hydro, and wind generators offer their entire capacities in the spot market while solar plants continue to derive low proportion of their revenues from contracts due to its intermittent nature. This highlights the dependence of these technologies on spot market dynamics for revenue generation. To support the transition toward a more reliable and sustainable energy system, reforms in market price settings must provide strong price signals that incentivise new capacity investments while promoting flexible generation.

Table 13 New Entrant Contract Revenues (Million Php/MW)

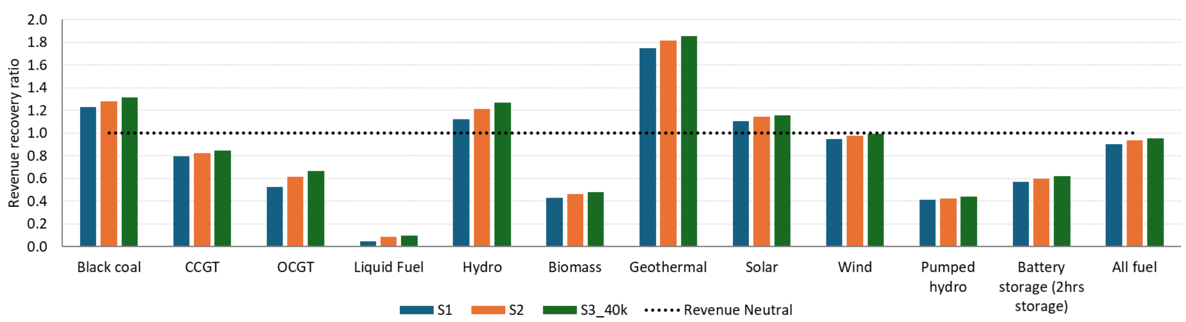
Scenario	Plant Type	2025	2026	2027	2028	2029	2030	Average
S1	Battery (Gen – Load)	-	-	-	-	-	-	-
	Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CCGT	-	2.58	2.37	2.15	2.24	2.86	2.03
	Coal	-	1.51	1.74	1.72	1.83	2.32	1.52
	Liquid Fuel	0.04	0.03	0.03	0.03	0.03	0.04	0.03
	Geothermal	1.61	2.26	1.79	1.95	2.01	2.58	2.03
	Hydro	1.25	1.41	0.77	0.74	0.77	0.87	0.97
	OCGT	-	-	-	-	2.35	2.95	0.88
	Pumped Hydro	-	-	-	-	-	-	-
	Solar	0.14	0.19	0.21	0.21	0.22	0.29	0.21
	Wind	-	-	-	-	-	-	-
S2	Battery (Gen – Load)	-	-	-	-	-	-	-
	Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CCGT	-	2.72	2.44	2.22	2.27	3.00	2.11
	Coal	-	1.61	1.79	1.78	1.85	2.48	1.58
	Liquid Fuel	0.05	0.04	0.03	0.03	0.03	0.04	0.04
	Geothermal	1.90	2.51	1.85	2.01	2.04	2.71	2.17
	Hydro	1.50	1.59	0.80	0.77	0.78	0.92	1.06
	OCGT	-	-	-	-	2.38	3.14	0.92
	Pumped Hydro	-	-	-	-	-	-	-
	Solar	0.15	0.20	0.22	0.22	0.22	0.30	0.22
	Wind	-	-	-	-	-	-	-
S3	Battery (Gen – Load)	-	-	-	-	-	-	-
	Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CCGT	-	2.79	2.51	2.27	2.29	3.09	2.16
	Coal	-	1.68	1.86	1.82	1.87	2.55	1.63
	Liquid Fuel	0.05	0.04	0.03	0.03	0.03	0.04	0.04
	Geothermal	2.00	2.61	1.90	2.06	2.06	2.79	2.24
	Hydro	1.59	1.66	0.82	0.78	0.79	0.95	1.10
	OCGT	-	-	-	-	2.41	3.24	0.94
	Pumped Hydro	-	-	-	-	-	-	-
	Solar	0.16	0.21	0.22	0.22	0.22	0.30	0.22
	Wind	-	-	-	-	-	-	-

6.5 Revenue Adequacy

In general, price caps should be designed to support future investment while avoiding significant negative impacts on the feasibility of existing generators. Despite the recent cost recovery trends for solar and wind, a broader perspective is required to evaluate revenue sustainability across all technologies. The **revenue adequacy ratio**, defined as the total gross revenue (spot and contract) divided by total costs, is a critical indicator of whether generation technologies recover their costs. The new entrant portfolio required to address reliability must be able to adequately recover its costs. If this does not occur, the portfolio will not be developed, leading to worse reliability. Conversely, over-recovery would incentivise additional investment, resulting in higher reliability. A ratio greater than 1 signifies over-recovery, while a ratio below 1 indicates under-recovery of costs. The ratio should ideally be close to 1. The modelling results in Figure 50 reveal key insights regarding revenue adequacy under different price settings.

With the increased price volatility in Scenario 1 and Scenario 2, several generation technologies still remain revenue inadequate, with ratios below 1.0. This indicates that the price settings under Scenario 1 and Scenario 2 are insufficient to incentivise the projected capacity outlook for that generation type. While solar and wind achieve revenue adequacy despite their intermittency, peaking plants like OCGTs, BESS, and pumped hydro fail to fully recover their costs and rely on the amended SPC and higher PPC levels to close the revenue gap. Conversely, certain new entrant generation types, such as geothermal and hydro, over-recover costs, suggesting the need for a portfolio-based approach to balance revenue outcomes. This approach would allow surplus revenues from over-recovering technologies to address revenue shortfalls in OCGTs, BESS, and pumped hydro. This is particularly important given the significant mismatches between VRE and demand, which require firming support from these technologies. In practice, portfolios will be developed with a mix of generation types to reliably meet demand going forward.

Figure 50 Cost Recovery for New Entrants at System Level (2025-2030)



At the system portfolio level, revenues in Scenario 1 and Scenario 2 fall short by approximately 9.9% and 6.5%, indicating a need for further adjustments. Scenario 3 models an optimal PPC of Php 40,000/MWh, which further improves revenue adequacy across generation types and shifts the recovery factor closer to 1. While the revenue adequacy ratio improves under Scenario 3, it remains 4.5% below 1. Given the calibrated price outcomes from the backcasting exercise are on the conservative side (Section 6.1), this shortfall may be considered reasonable.

The balancing act between achieving revenue adequacy and avoiding over-recovery highlights the importance of careful price cap adjustments. While an adequacy ratio exceeding 1 reflects over-recovery, maintaining ratios close to 1 ensures cost recovery without introducing inefficiencies. These modelling results demonstrate how an increased PPC supports better revenue recovery, particularly for technologies like peaking plants, while aligning system-wide revenues more closely with total costs.

Table 14 below provides a detailed breakdown of revenue adequacy by fuel type over the 2025–2030 period. This table underscores the variation in recovery across technologies, with solar, coal, geothermal and hydro performing well, while peaking technologies show under-recovery of cost.

Table 14 New Entrant Revenue Adequacy Ratio (2025-2030)

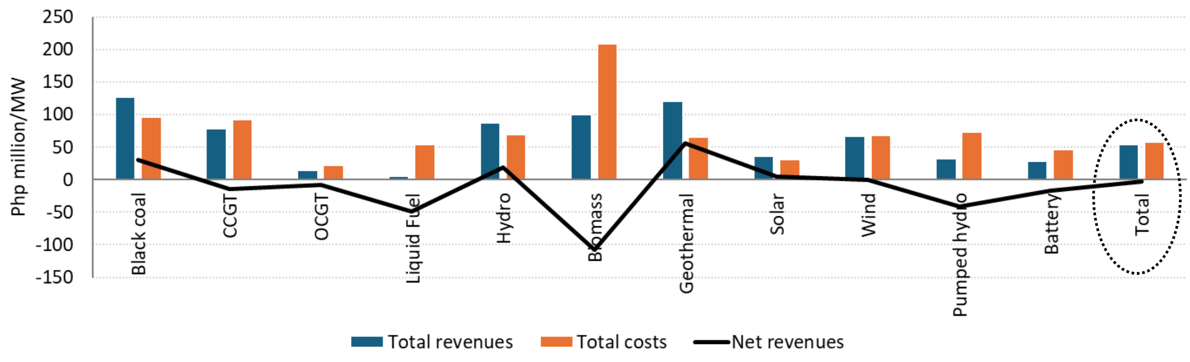
	S1	S2	S3
Black coal	1.230	1.280	1.315
CCGT	0.797	0.825	0.845
OCGT	0.528	0.616	0.667
Liquid Fuel	0.045	0.087	0.095
Hydro	1.125	1.215	1.267
Biomass	0.428	0.464	0.483
Geothermal	1.748	1.814	1.858
Solar	1.108	1.146	1.155
Wind	0.951	0.975	0.993
Pumped hydro	0.411	0.425	0.441
Battery storage (2hrs storage)	0.570	0.599	0.620
All fuel	**0.9013**	**0.9346**	**0.9544**

Figure 51 below illustrates the comparison of total revenue/MW, total costs/MW, and net revenue/MW for new entrant technologies under Scenario 3 over the period 2025 to 2030. It provides additional insights into the revenue adequacy of various fuel types by visually representing their performance in relation to cost recovery.

For most technologies, the total revenue/MW aligns closely with or exceeds total costs/MW, reflecting improved revenue adequacy under the amended SPC and increased PPC of Php 40,000/MWh. Hydro and geothermal continue to show strong net revenues, reflecting their consistent ability to recover costs. Similarly, solar and wind perform near or slightly above cost recovery levels, further confirming their viability despite intermittency.

In contrast, OCGTs, BESS, and pumped hydro remain below the cost recovery threshold while liquid fuel plants, as expected, demonstrate negative net revenues due to high costs and low utilisation, making them the least viable. However, given the system needs a balanced mix of technologies to manage system reliability with increasing VRE Integration, the net revenue (cost recovery) for the system-wide new entrant portfolio level would be the most appropriate metric and shows net revenues close to zero which supports the optimal PPC of Php 40,000/MWh.

Figure 51 Scenario 3 Revenues and Costs per MW (2025-2030)



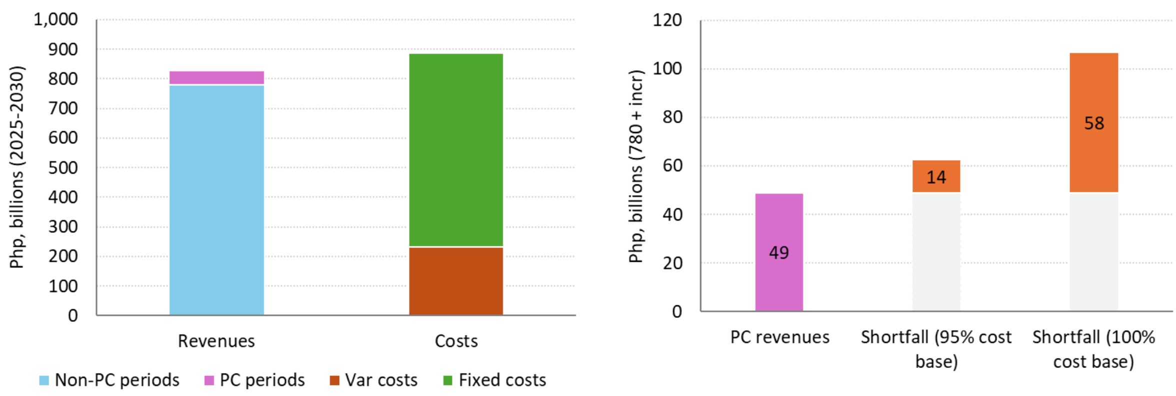
6.5.1 Revenue and Implied PPC Requirements

The SPC and PPC are positively correlated with revenues. However, the extent of this correlation varies for each generation type, particularly depending on the availability of the generator to contribute during tight supply and demand conditions.

Due to this dynamic, and previous analysis showing low solar and wind contributions as a potential driver of supply and demand conditions, VRE would have a much smaller share of its revenues linked to Price Cap (PC) periods.[11] In other words, the feasibility of VRE is tied more closely to fuel prices than to the PPC. By contrast, firming generation types are dispatchable and therefore capture a higher share of revenues during PPC periods.

The extent of the revenue portion directly related to PPC, and its relativity to the cost gap, provides an indication of the required PPC for revenue adequacy. In the modelling, only revenues earned during tight supply and demand periods are affected by changes in the PPC. As such, there is an amplifying effect on the required or optimal PPC.

Figure 52 Revenues and Costs by Component (Scenario 2)



This is illustrated in Figure 51, based on Scenario 2 with a PPC of 32,000/MWh. The chart on the left shows revenues broken down into periods of tight supply (PPC-related, pink) and non-PPC

[11] Defined as periods of volatility where energy prices are impacted by the primary price cap, and/or is subject to high prices under active SPC periods.

periods (blue). The total cost wedge exceeds total revenues, and the only way to address this shortfall (within the context of this project) is to increase the PPC, which in turn raises the pink PPC-related revenue wedge.

The chart on the right in Figure 51 zooms in on the upper section of the chart on the left. It shows 49 billion Php in PPC revenues across the system-wide new entrant portfolio. However, an additional 58 billion Php is required for full cost recovery, or 14 billion Php to reach 95% of the cost base. The 14 billion shortfall is equivalent to scaling the PPC revenue wedge by 28% (14/49). From this, we can infer that recovering 95% of the cost base requires increasing the PPC by 28% x 32,000/MWh, or 9,000/MWh. This corresponds to our optimal PPC recommendation of 40,000/MWh.[12]

6.6 Tariff Impacts

The impact of various market price settings on the retail tariff is assessed to determine how price adjustments, aimed at ensuring generator revenue adequacy, affect the consumers. Establishing a baseline for comparison, MERALCO's average electricity tariff in 2023 is selected as the distribution utility serves the largest share of electricity demand among all utilities. Figure **53** shows that in 2023, the average generation charge was at 6,961 Php/MWh, accounting for about 60% of the overall average residential electricity rate of more than 11,500 Php/MWh. This makes the generation cost component the primary focus of the retail tariff assessment.

The generation cost component across the modelled scenarios is presented Table 15. The average spot purchase and contract difference payments are seen to increase in line with the increasing SPC and PPC values. The other components of the retail electricity tariff are presented in Table 16. These components are assumed to be constant throughout the forecast horizon as these amounts are less likely to vary drastically.

Figure 54 shows the resulting electricity tariff across the different scenarios, averaged throughout the forecast horizon, while Figure 55 shows the overall generation and tariff impact of scenarios 2 and 3 relative to Scenario 1. Updating the SPC while maintaining the current PPC imposes a 5.7% increase in the generation cost and 3.5% increase in the electricity tariff as seen in Scenario 2. Setting the PPC at the optimal level of 40,000 Php/MWh (Scenario 3) results to 8.8% increase in generation cost compared to S1. Although the PPC is significantly higher in S3, the overall tariff impact is limited to 5.5% from the base scenario. With this, the new price cap setting along with the updated SPC, allows new entrants to recover costs, thereby encouraging the target renewable energy mix while maintaining reliable and sustainable electricity in the long run, for a small increase to the overall tariff.

[12] The modelling validated the PPC in 5,000/MWh increments. Note this calculation only holds true assuming the SPC parameters are not significantly suppressing PPC price signals.

Figure 53 2023 Average Electricity Tariff – MERALCO

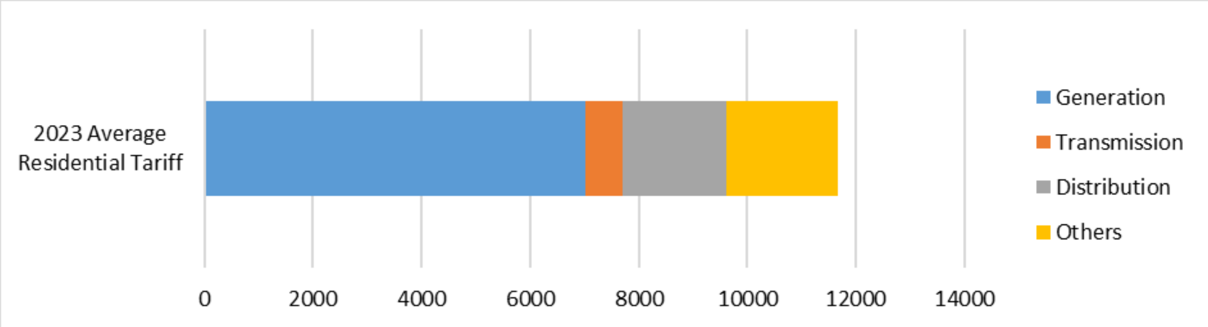


Table 15 Generation Cost Component, in Php/MWh (based on real 2023 Php)

Scenario	Description	Generation Cost	Spot Purchases	Contract Difference
S1	PPC at 32k, current SPC	5531	5138	393
S2	PPC at 32k, amended SPC	5845	5430	415
S3	PPC at 40k, amended SPC	6018	5591	427

Table 16 Other Tariff Components, in Php/MWh (based on real 2023 Php)

Tariff Component	Cost Php/MWh	Category
Transmission Charge	680.03	Transmission Charge
System Loss Charge	613.02	Others
Distribution Charge	980.3	Distribution Charge
Supply Charge	497.9	Distribution Charge
Metering Charge	335	Distribution Charge
Universal Charge	243.7	Others

Figure 54 Electricity Tariff Components and Average Spot Prices 2025-2030 (based on real 2023 Php)

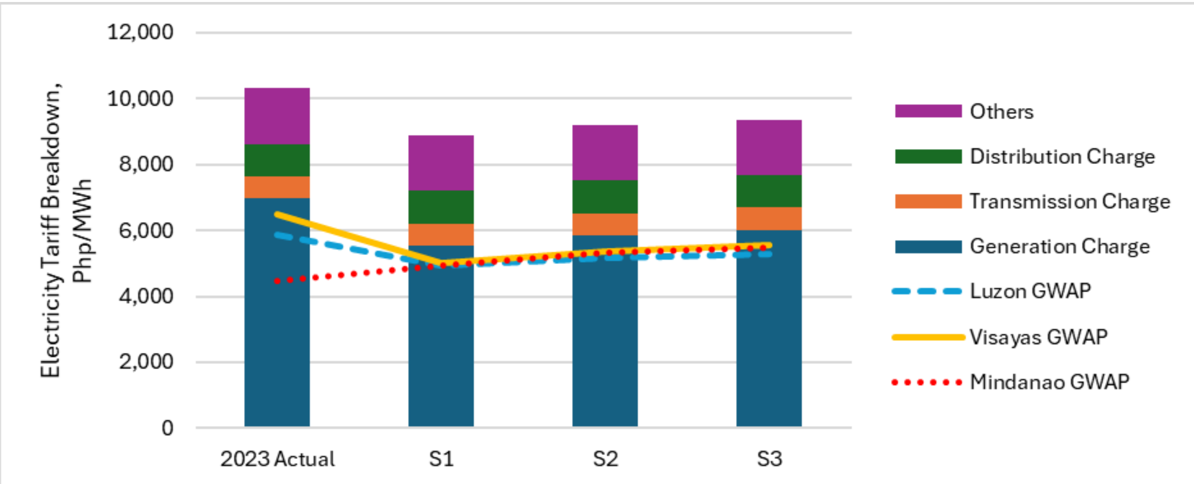
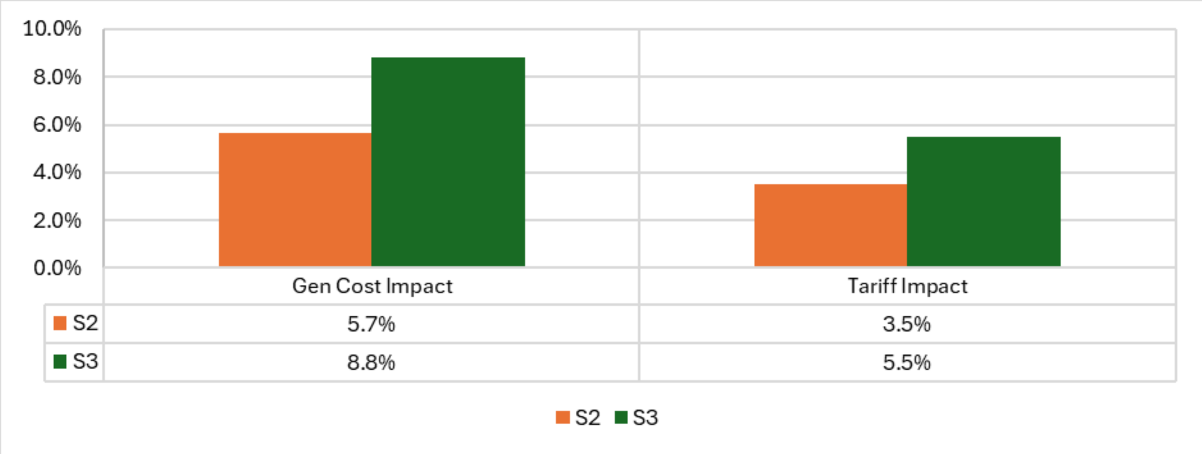


Figure 55 Generation Cost and Tariff Impact relative to Scenario 1



6.6.1 Economic Cost Impact

The assessment of tariff impacts only reflects the direct cost to consumers. However, the economic cost is a better metric, as it includes both the end-user tariff and the cost of the implied reliability delivered under each scenario. In Scenarios 1 and 2, since the new entrant capacity does not adequately recover costs, it is reasonable to assume that part of this portfolio would not be developed. This would reduce supply and result in a worse level of reliability compared with Scenario 3. A more meaningful comparison is therefore obtained when the cost of unserved energy is included.

Given there is no established value of customer reliability, and the level of reliability associated with the PEP new entrant outlook is implied, only an illustrative comparison is provided. A value of customer reliability of 64,000/MWh, and loss of load expectation (LOLE) of 1 day in Scenario 3, and 5 and 3 days for Scenarios 1 and 2, respectively, is assumed. The overall cost is calculated as a weighted average of demand served (at the end-user tariff) and unmet load (at the value of customer reliability).

This analysis presents a different finding: Scenario 3 results in the lowest economic cost. The hidden costs of unserved energy under Scenario 1 outweigh the increase in end-user tariffs associated with an increase in the optimal PPC to 40,000/MWh.[13] This calculation illustrates the overarching trade-off that must be considered in power system planning: the cost of additional investment in the power system versus the level of reliability that is desired or appropriate for the WESM.

Table 17 Example of Economic Cost Impact

Scenario	Tariff Php/kWh	LOLE (days a year)	Loss of load %	Economic cost Php/kWh	Tariff impact	Economic impact
S1	8.88	5.0	1.37%	9.64	0.0%	0.0%
S2	9.20	3.0	0.82%	9.65	3.5%	0.1%
S3_40k	9.37	1.0	0.27%	9.52	5.5%	-1.2%

[13] This is highly contingent on the assumptions used.

6.7 Conclusion

The analysis in the section explores the impact of price caps on revenue adequacy and generator viability across three scenarios, combining historical calibration with forward-looking modelling to assess cost recovery for existing and new entrant generators.

The backcasting process provides a robust foundation by ensuring the model aligns with historical outcomes, enhancing credibility and accuracy. Regional energy prices capped at Php 32,000/MWh closely align with historical price duration curves at lower price levels. Deviations occur at higher spot prices, leading to lower annual simulated prices across Luzon and Visayas. This highlights the conservative back cast, acknowledging details such as intra-nodal transmission constraints that are not explicitly modelled. The calibration provides a sound basis for the forward projections and ensures that the insights derived from Scenarios 1, 2, and 3.

Scenario 1 establishes the baseline by assessing the current PPC and SPC settings, revealing frequent SPC active intervals and suppressed price signals that result in revenue inadequacies for peaking plants and flexible generators. Scenario 2 introduces an amended SPC that raises the price threshold, significantly reducing the frequency of active SPC intervals (from 4.5% in Scenario 1 to 0.4% in Scenario 2) and improving cost recovery opportunities for most technologies. However, despite these improvements, several technologies—such as OCGTs, BESS, and pumped hydro—remain revenue inadequate under the amended SPC, necessitating further adjustments.

Scenario 3 builds upon these findings by retaining the amended SPC while introducing an optimal PPC of Php 40,000/MWh. This adjustment generates stronger price signals, enabling technologies with persistent revenue shortfalls to recover costs more effectively. The system-wide revenue adequacy ratio improves to 0.954 in Scenario 3, reducing the revenue gap to within a 5% range of recovering its full cost base corresponding to a significant improvement over the shortfalls of 9.9% and 6.5% observed in Scenarios 1 and 2, respectively.

While hydro and geothermal consistently achieve cost recovery, and solar and wind remain viable despite intermittency, peaking technologies such as OCGTs, BESS, and pumped hydro continue to rely on higher price caps (or other generation types in the portfolio) to address revenue shortfalls. The results from Scenario 3 demonstrate that the proposed PPC effectively enhances revenue adequacy without introducing inefficiencies, and addressing the challenges identified in earlier scenarios.

Setting the PPC at the optimal level of 40,000 Php/MWh in Scenario 3 results to 8.8% increase in the generation cost component of retail tariffs compared to the base scenario. Although the PPC is significantly higher, it is still below the original 64,000 Php/MWh, and the overall tariff impact is limited to an increase of 5.5%. The new entrant portfolio would not be developed in full under Scenarios 1 and 2 due to under-recovery of cost and would result in a less reliable system. A more accurate assessment is to include the economic cost of reliability. The example analysis shows although Scenario 3 results in a higher end-user tariff, the reduction in unserved energy costs can more than offset the tariff increase which would result in a lower economic cost under Scenario 3.

These modelling outcomes underscore the critical role of calibrated price caps in improving cost recovery, which in turn incentivise investment to drive reliability outcomes. Scenario 3 offers a balanced and effective framework for achieving these objectives, ensuring the financial sustainability of new entrant generators while facilitating the transition to a cleaner and more adaptable energy mix.

7 Key findings

The modelling analysis highlights critical findings on supply dynamics, pricing behaviour, revenue recovery, and tariff impacts, underscoring how adjustments to the SPC and PPC influence the power system reliability, efficient investment and sustainability.

Supply Outlook

The projected new capacity additions are heavily weighted toward renewable energy, with solar and wind supported by storage technologies such as BESS and pumped hydro (PHES), and also flexible gas generation. This capacity mix, as shown in Table 18 below, is representative of broader RE generation targets in the WESM, complemented by technologies that ensure system flexibility and reliability.

Table 18 New Entrant contribution to Supply Mix by Technology

Technology	Contribution to New Entrant mix (%)
Solar	35%
Wind	21%
BESS & PHES	13%
Flexible gas generation	23%

Spot Prices

Under Scenario 1, the system-wide GWAP is projected to average Php 4,956/MWh. In Scenario 2, the amended SPC leads to an increase in price volatility, resulting in a 6.6% higher GWAP of Php 5,283/MWh. The increased volatility, which affects approximately 8% of the year, is a direct outcome of raising the SPC threshold, allowing for less frequent price suppression and improved market price signals.

Amended SPC

The current SPC frequently constrains prices, with around 4.5% of intervals between 2025 and 2030 being affected. The current SPC suppresses pricing signals and would limit generators' ability to recover fixed costs. In some instances, the administered price is lower than peaking generation short-run marginal costs which is suboptimal and may result in withdrawal of capacity in periods of tight supply. In Scenario 2, the amended SPC reduces these intervals significantly to just 0.4%, allowing for more SRMC headroom for all plants (except oil). This adjustment improves cost recovery opportunities for most technologies, although oil-based generators remain challenged due to their high and volatile costs. The active SPC intervals under Scenario 3 increase to 1.0% as expected with the higher 40,000/MWh PPC, which is still much lower than Scenario 1.

Revenue Recovery

New entrant solar and wind projects are projected to recover their costs under both scenarios. However, flexible and firming generation technologies, which play a critical role in supporting VRE integration, face revenue shortfalls. At the portfolio level, the system remains under-recovered, with revenue gaps of 10% in Scenario 1 and 7% in Scenario 2, indicating persistent challenges in achieving full cost recovery. Under these scenarios, we would expect the new entrant portfolio required to meet increasing demand would not be developed in full resulting in lower reliability than planned for under the PEP.

Optimal PPC

Scenario 3 explores the impact of raising the PPC to Php 40,000/MWh. This adjustment reduces revenue shortfalls, ensuring new entrants recover costs within 5%. The higher PPC increases price volatility and raises GWAP by 9.8%. The amended SPC and higher PPC, improves price signals and supports peaking plants and other generators in achieving adequate revenue recovery at the portfolio level. Adequate cost recovery is required for sustainable investment which contributes to ongoing power system reliability.

Tariff Implications

Total generation costs are projected to rise by 5.7% under Scenario 2 and 8.8% under Scenario 3. However, the corresponding tariff impacts remain moderate, with increases of 3.5% and 5.5%, respectively. These adjustments are essential for ensuring long-term sustainability while minimising impacts on consumers. However, the economic cost of unserved energy should be included in any end-user cost assessment. In the example analysis, the higher tariff-cost under Scenario 3 is more than offset by the reduction in unserved energy costs relative to Scenario 1 and 2. This calculation illustrates the overarching trade-off that must be considered in power system planning: the cost of additional investment in the power system versus the level of reliability that is desired or appropriate for the WESM.

These findings highlight the advantages of the optimal PPC in addressing revenue adequacy and addressing reliability requirements. By providing sufficient price signals, the revised price settings incentivise new capacity and support flexible generation, ensuring a smooth transition to a more reliable and sustainable energy system. Scenario 3 also meets its additional evaluation criteria by promoting market efficiency and competition, securing adequate revenue for new entrants within a system-wide portfolio. The recommended adjustment to the PPC safeguards against sustained volatility through the amended SPC, ensuring a balance between revenue recovery for generators and safeguards for the market and end-use customers. The amended SPC and PPC of 40,000/MWh, supported by modelling results, align with broader WESM planning criterion relating to affordability and reliability.