# Annual Market Assessment Report

## 26 December 2024 to 25 December 2025

**JUNE 2026**

This Report is prepared by the
Philippine Electricity Market Corporation –
Market Assessment Department and approved
by the Market Surveillance Committee

Document Information Classification: Public

## EXECUTIVE SUMMARY

By the end of the 2025 Billing Year, the total system-wide registered capacity reached 30,093.8 MW, reflecting a modest 0.44% increase from the 29,962 MW recorded in 2024. Compared with the 2023 level of 27,227.70 MW, registered capacity increased by 10.53%, indicating continued expansion of registered generation resources over the three-year period. Regional registered capacities increased in both Luzon and Visayas by 0.17% and 4.51%, respectively, compared to 2024. In contrast, Mindanao recorded a 1.63% decrease.

Renewable Energy (RE) plants accounted for the majority of newly registered capacity in 2025. Of the 855 MW newly registered in the WESM, approximately 87.23% or an aggregated capacity of 745.8 MW, came from RE plants. This reflected the continued entry of renewable generation resources into the market.

Capacities Offered/Nominated remained the largest component of the registered capacity profile, amounting to 20,434.46 MW or approximately 67.9% of registered capacity. This represents an increase of 15.09% from 2023 and 8.13% from 2024, indicating a continued improvement in the volume of capacity made available to the market.

Capacity Not Offered/Nominated accounted for 5,275.23 MW, or around 17.53% of registered capacity in 2025. This was higher by 157.37% compared with 2023 and 15.88% compared with 2024. The increase was mainly attributable to resource constraints and capacity derations experienced by plants in the WESM.

Capacity on Commissioning declined significantly to 602.98 MW in 2025, representing around 2.0% of registered capacity. This corresponds to an 82.09% decrease from 2023 and a 58.80% decrease from 2024, largely due to the eventual commercial operation of plants that were previously undergoing testing and commissioning activities.

Capacity on Outage stood at 3,513.92 MW, equivalent to approximately 11.68% of registered capacity. This was 11.03% higher than in 2023 but 4.30% lower than in 2024.

An assessment of capacity on outage by plant type shows that coal plants continued to account for the largest share of outages in 2025, followed by natural gas and oil-based plants. This ranking has remained broadly consistent across the comparative years from 2023 to 2025, indicating that outages were still concentrated among major conventional generation technologies. In terms of capacity on outage by category, planned outages increased by 6.44% to 1,338.14 MW compared to 2024. In contrast, both forced and maintenance outages declined by 6.73% and 33.53%, respectively.

Coal-fired plants remained the dominant source of generation, contributing more than half of total generation in every quarter, with a quarterly share ranging from 55% to 59%, higher than coal's approximate 40.5% share in registered capacity. While Natural Gas plants remained material at around 17% to 20%, which appears higher than their share in registered capacity. This indicates that the grid remained heavily dependent on these generation despite the recorded outages from these plant types during the year.

Renewable energy resources contributed 25.49% of total generation in 2025. While this represents a meaningful contribution, it remains below the DOE's reference target of 35% renewable energy share in the power generation mix by 2030. The DOE's Power

Development Plan 2023–2050 adopts a national RE power generation mix target of 35% by 2030 and 50% by 2040 as the reference scenario.

System demand increased from 12,858 MW in 2023 to 13,904 MW in 2024, representing a year-on-year growth of 8.13%. In 2025, demand reached 13,963 MW, reflecting only a marginal increase of 0.43% from the previous year. While the effective supply increased from 16,369 MW in 2024 to 17,969 MW in 2025, equivalent to a 9.78% increase. As a result, the supply margin widened from 2,465 MW in 2024 to 4,006 MW in 2025. This indicates an improvement in the average supply-demand balance and suggests a stronger capacity adequacy position compared with the previous year.

The year-on-year comparison of the Load-Weighted Average Price (LWAP) shows a decrease from PHP 5,583/MWh in 2024 to PHP 3,981.72/MWh in 2025, equivalent to a reduction of approximately 28.68%. This decline suggests relatively improved supply conditions and reduced market tightness in 2025 compared with the previous year, although price movements may also have been influenced by other factors such as demand levels, outage conditions, generation mix, and offer behavior.

Daily spot energy transactions (in MWh) declined from 22.91% in 2024 to 17.63% in 2025. This indicates a lower reliance on the spot market despite the overall increase in electricity demand. The decline suggests that a larger share of energy requirements may have been covered through bilateral contracts or other contracted arrangements, while spot market transactions accounted for a smaller portion of total load.

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# ANNUAL MARKET ASSESSMENT REPORT

This Annual Market Assessment Report (AMAR) provides an evaluation of the integrated operations of the Wholesale Electricity Spot Market (WESM) across Luzon, Visayas, and Mindanao for the covered period (26 December 2024 to 25 December 2025). It includes an overview of market performance, trends, and the underlying drivers of these results, offering a basis for assessing market competition and determining the prevailing conditions in the WESM.

## I. MARKET DEVELOPMENT

This section presents the key developments in the Philippine electricity market during the assessment year, with emphasis on policy and regulatory issuances, significant power system events, and demand-related observations. It discusses measures affecting the WESM, including refinements to market mitigation mechanisms and the determination of market share limitations, as well as major system conditions that influenced market operations.

### A. Policy and Regulatory Developments

- Amendments to the Pre-emptive Mitigating Measure in the Wholesale Electricity Spot Market (WESM)[1]

  In 2025, the Energy Regulatory Commission (ERC) issued amendments to the existing Secondary Price Cap (SPC) mechanism through a resolution amending Resolution No. 07, Series of 2021, entitled “A Resolution Adopting Amendments to Resolution No. 04, Series of 2017 Entitled ‘Amendments to the Pre-emptive Mitigating Measure in the Wholesale Electricity Spot Market (WESM)’.” The resolution was approved on 26 November 2025 and took effect on 31 December 2025.

  The resolution provides further refinements to the existing SPC framework, including adjustments to the parameters and conditions governing the activation of the mitigating measure. These enhancements are intended to improve the responsiveness of the mechanism during periods of abnormal market conditions while preserving appropriate price signals for market participants. Table 1 summarizes the key amendments introduced under the revised SPC mechanism.

[1] ERC Resolution No. 26, Series of 2025, A Resolution Amending Resolution No. 07, Series of 2021, Entitled “A Resolution Adopting Amendments to Resolution No. 04, Series of 2017 Entitled "Amendments to the Pre-Emptive Mitigating Measure in the Wholesale Electricity Spot Market (WESM)" Link: https://www.erc.gov.ph/Files/Render/issuance/46960

**Table 1: Summary of Changes**

| Parameter | ERC Resolution No. 7, Series of 2021 | ERC Approved in ERC Resolution No. 26, Series of 2025 |
|---|---|---|
| SPC Value | PHP 6,245 | PHP 7,423 |
| Cumulative Price Threshold | PHP 9,000 | PHP 12,413 |
| Rolling Average Period | 3 days / 72 hours / 864 five-min intervals | 3 days / 72 hours / 864 five-min intervals |
| Review of SPC Parameters | - | Five (5)-year review cycle or earlier if warranted by significant market developments |

- Setting of Installed Generating Capacity and Market Share Limitations for 2025[2]

  In 2025, the Energy Regulatory Commission (ERC) approved Resolution No. 07 and Resolution No. 14, Series of 2025, establishing the Installed Generating Capacity and Market Share Limitations per Grid and National Grid for the year 2025. The ERC Resolution No. 14 was approved on 30 July 2025 and took effect on 15 August 2025

  The determination of grid-level and national-level installed capacity and market share thresholds supports the ERC's mandate to promote a competitive and efficient electricity market by ensuring that no single participant or group of participants obtains excessive influence over market outcomes.

## B. System Events

- Yellow Alert Conditions

  In 2025, the Philippine power system experienced several Yellow Alert conditions across the major grids, reflecting periods of tight supply margins due to a combination of increased electricity demand, generating unit outages, and derated capacities of available generation resources (See Annex B. Yellow Alert Occurrences – 2025 for further details).

[2] ERC Resolution No. 07, Series of 2025, A Resolution Setting the Installed Generating Capacity and Market Share Limitation Per Grid and National Grid for 2025 and ERC Resolution No.14, Series of 2025, A resolution Setting the Adjusted Installed Generating Capacity and Market Share Limitation Per Grid and National Grid for 2025 Link: https://www.erc.gov.ph/Files/Render/issuance/46066 and https://www.erc.gov.ph/Files/Render/issuance/45158

- Market Suspension Event

  In 2025, the WESM was placed under market suspension in response to significant system disturbances arising from natural calamities and their impact on grid operations (See Section III.B and Annex C: Market Intervention and Market Suspension List for further details).

  Two major earthquake events occurred during the year, affecting the Visayas and Mindanao regions. The earthquake incident in Cebu resulted in the suspension of market operations in the affected sub-grids, particularly the Bohol and Leyte sub-grids, due to the need to manage system conditions and ensure the reliability and security of grid operations following the disturbance.

  In addition, a market suspension event was declared in the Visayas region following the impact of Typhoon Tino, which affected power system operations and required the implementation of contingency measures to support grid stability and facilitate the restoration of normal market activities

### C. Combined Peak Demand of the Philippines

- A new all-time high for combined peak demand and reserve requirement was recorded on 23 April 2025 at 1440h, reaching 21,310.8 MW. This surpassed the previous high of 20,556 MW which was recorded on 09 May 2024 at 1430h. The observation coincided with the summer season, when the Philippine Atmospheric, Geophysical and Astronomical Services Administration (PAGASA) recorded heat index levels ranging from 42 to 51 degrees Celsius, which fall under danger level[3].

## II. Market Assessment

### A. Supply

#### i. Registered Capacity

By the end of the 2025 Billing Year, the total system-wide registered capacity reached 30,093.8 MW, reflecting a modest 0.44% increase from the 29,962 MW recorded in 2024. Compared with the 2023 level of 27,227.70 MW, registered capacity increased by 10.53%, indicating continued expansion of registered generation resources over the three-year period.

Regional registered capacities and their corresponding year-on-year changes from 2023-2025 are presented in Table 2. The table provides a comparative

[3] D. Flores. Philstar Global: Blistering heat to persist in 25 areas, up to 45°C
Link: https://www.philstar.com/headlines/weather/2025/04/23/2437766/blistering-heat-persist-25-areas-45c

view of capacity movements across regions and highlights the areas that contributed to the overall system-wide increases.

**Table 2: Regional Registered Capacity – 2023 to 2025**

| Region | Registered Capacity per Year | | | Year-on-Year Change | |
|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2023 to 2025 | 2024 to 2025 |
| Luzon | 19,443.17 | 21,863.30 | 21,901.30 | 12.64% | 0.17% |
| Visayas | 3,451.60 | 3,676.30 | 3,842.10 | 11.31% | 4.51% |
| Mindanao | 4,331.90 | 4,422.40 | 4,350.40 | 0.43% | -1.63% |

In 2025, total registered capacity increased by a net 131.80 MW from the previous year. This net increase was mainly driven by the registration of new power plants with an aggregated capacity of 855 MW, as enumerated in *Annex A-1: Newly Registered Plants*. These additions were partly offset by capacity changes of -556.4 MW, which include plants that were mothballed, de-registered, ceased operations, or removed due to disaggregation. Other capacity adjustments also affected the final registered capacity, including a 556.4 MW reduction and 375.3 MW of capacity associated with disaggregated, as detailed in *Annex A-2: Plants with Changes in Capacity*.

Renewable Energy (RE) plants accounted for the majority of newly registered capacity in 2025, Of the 855 MW newly registered in the WESM, approximately 87.23% or an aggregated capacity of 745.8 MW, came from RE plants. This reflected the continued entry of renewable generation resources into the market.

A significant portion of the disaggregation activity involved the Iligan Diesel Power Plant (10IDPP_G01) with capacity of 102 MW. This plant was disaggregated into 19 plants with a combined capacity of 100.5 MW.

Per resource type, coal-fired power plants continued to account for the largest share of registered capacity in 2025, with 12,175 MW, equivalent to 40.46% of the total registered capacity. However, coal's share declined from 41.8% in 2024 and 44.9% in 2023, indicating a gradual reduction in its relative contribution to the overall capacity mix, as shown in figure 1.

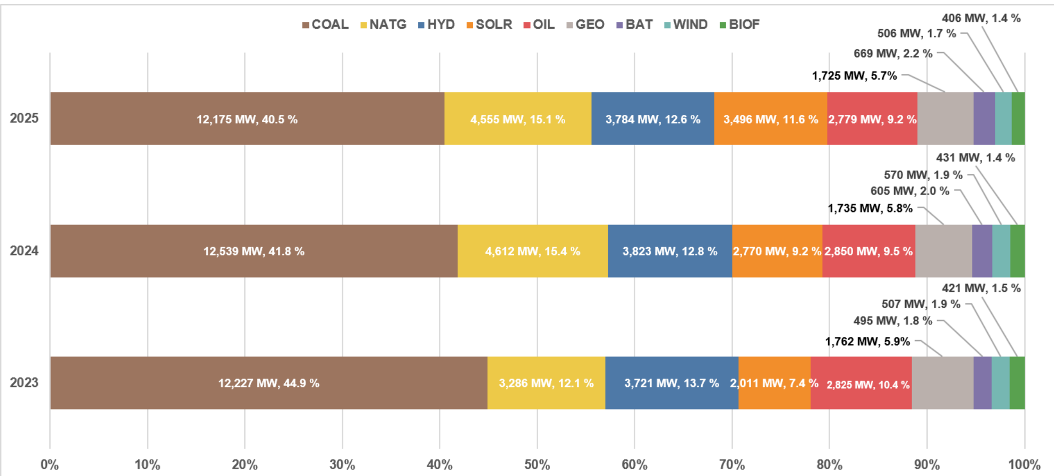


**Figure 1: Capacity Mix – 2023 to 2025**

On a MW basis, registered coal capacity decreased by 364.1 MW in 2025. This reduction was mainly attributable to changes in the registered Pmax of 23 plants, which accounted for the largest capacity adjustment among the resource types during the year.

Meanwhile, registered RE capacity increased by approximately 6%, from 9,356 MW in 2024 to 9,917.4 MW in 2025. The increase was primarily driven by solar capacity, which rose by 725.6 MW, equivalent to a 26.1% increase from the previous year. Solar capacity reached 3,496 MW in 2025 representing 11.62% of total registered capacity and making the 4th largest resource type in terms of MW share.

The increasing share of solar capacity from 2023 to 2025 reflects the continued entry of solar generation facilities into the WESM. Among the newly registered solar plants in 2025 were the following (see full list on *Annex A-1*):

**Table 3: Registered Solar Plants - 2025**

| Facility Name | Registered Capacity (MW) | Quarter of Registration |
|---|---|---|
| Olongapo Solar Power Project (SPP) – Phase 1 | 172.2 | 4th Quarter |
| San Isidro Solar Power Project | 100.5 | 4th Quarter |
| Cordon Solar Power Project | 52.7 | 1st Quarter |

As shown in Figure 2, the 4th quarter recorded the highest newly registered capacity in 2025, totaling 365.7 MW. This was largely driven by solar plants, which contributed 354.7 MW, while oil accounted for 11 MW. The data indicate a strong concentration of solar capacity registrations in the 2nd half of the year, compared with the more varied mix of plant types registered during the 1st and 2nd quarters.

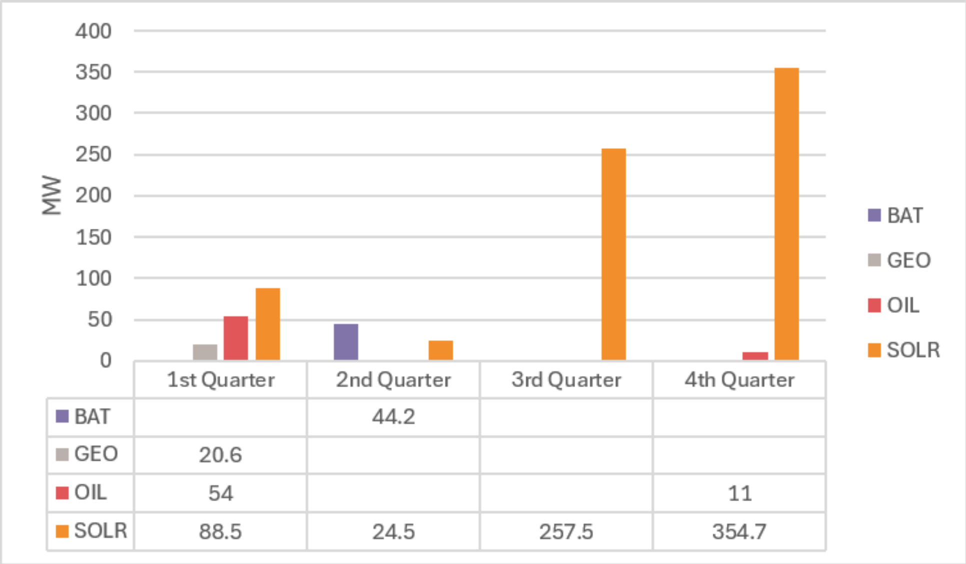



**Figure 2: Newly Registered Capacities per Quarter – 2025**

Figure 3 presents the registered capacity by plant age and technology type as of the December 2025 billing period. The registered generation portfolio remains heavily concentrated in relatively new assets, with the 0–10 year age bracket accounting for approximately 16,044 MW, or around 56% of total registered capacity. This indicates that a significant portion of the country's generation fleet has been added within the past decade. Within this age group, coal plants account for the largest share at about 6,943 MW, followed by solar at 3,467 MW and natural gas at 1,773 MW. This reflects both the scale of recent capacity expansion and the continued presence of conventional generation technologies alongside renewable additions.

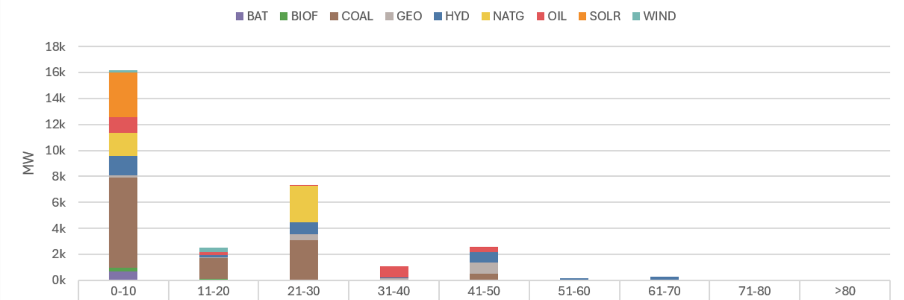
Renewable energy technologies are also strongly represented among younger plants. Solar capacity is concentrated almost entirely in the 0–10 year bracket, accounting for approximately 22% of capacity within that age group, underscoring the rapid growth of solar development and its increasing presence in the generation mix. Battery energy storage capacity is likewise recorded only in the 0–10 year bracket, indicating that storage remains an emerging but increasingly relevant component of the generation mix.

The 21–30 year age bracket represents the second-largest concentration of registered capacity, driven mainly by coal, natural gas, hydropower, and geothermal plants. This suggests that a substantial block of mid-life generation mix will remain important to the market in the near to medium term, while also requiring continued maintenance, performance monitoring, and potential rehabilitation planning

Hydropower dominates the oldest age categories, accounting for all registered capacity in the 51–60, 61–70, and 71–80 year age brackets. This highlights the long operational life of hydroelectric facilities and their enduring contribution to the generation mix.

The figure likewise showed that geothermal capacity is concentrated in the 21–50 year age range, especially in the 41–50 year bracket. This suggests geothermal remains a mature baseload renewable resource, but some facilities may require modernization over time given their age.

Oil-based capacity is spread across several age groups, particularly the 0–10, 31–40, and 41–50 year brackets. This may indicate that some oil plants continue to serve system reliability, reserve, or peaking requirements despite the broader shift toward lower-carbon technologies.




| | 0-10 | 11-20 | 21-30 | 31-40 | 41-50 | 51-60 | 61-70 | 71-80 | >80 |
|---|---|---|---|---|---|---|---|---|---|
| WIND | 171.00 | 335.10 | | | | | | | |
| SOLR | 3,467.00 | 19.50 | | | | | | | 9.50 |
| OIL | 1,193.00 | 250.50 | 48.00 | 857.00 | 430.00 | | | | |
| NATG | 1,772.50 | | 2,782.00 | | | | | | |
| HYD | 1,462.90 | 125.70 | 912.40 | 91.80 | 762.10 | 150.70 | 255.20 | 23.00 | |
| GEO | 177.60 | 68.30 | 490.10 | 140.00 | 849.20 | | | | |
| COAL | 6,943.30 | 1,627.10 | 3,074.40 | | 529.90 | | | | |
| BIOF | 310.40 | 95.90 | | | | | | | |
| BAT | 668.70 | | | | | | | | |

**Figure 3: Age of Registered Plants per Resource Types – 2025**

## ii. Capacity Profile

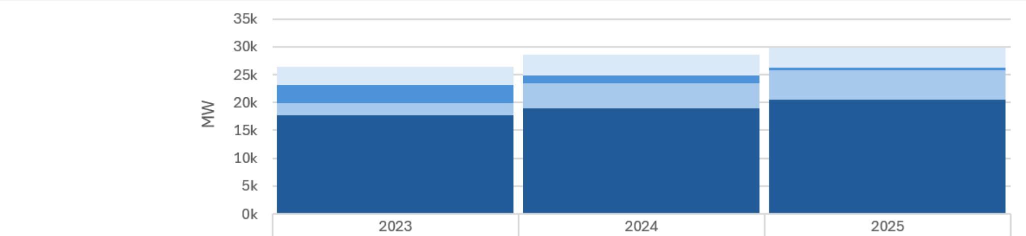
In 2025, Capacities Offered/Nominated remained the largest component of the registered capacity profile, amounting to 20,434.46 MW or approximately 67.9% of registered capacity. This represents an increase of 15.09% from 2023 and 8.13% from 2024, indicating a continued improvement in the volume of capacity made available to the market. On a quarterly basis, offered/nominated capacity was highest in the 2$^{nd}$ quarter at 21,422.38 MW before easing in the 3$^{rd}$ and 4$^{th}$ quarters.

Capacity Not Offered/Nominated accounted for 5,275.23 MW, or around 17.53% of registered capacity in 2025. This was higher by 157.37% compared with 2023 and 15.88% compared with 2024. The increase was mainly attributable to resource constraints and capacity derations experienced by plants in the WESM. Notably, capacity not offered/nominated remained elevated throughout the year, reaching its highest quarterly level in the 3$^{rd}$ quarter at 5,471.33 MW and remaining broadly similar in the 4$^{th}$ quarter at 5,451.75 MW. This suggests that availability-related limitations continued to affect a material portion of the registered capacity despite the increase in offered capacity.

Capacity on Commissioning declined significantly to 602.98 MW in 2025, representing around 2.0% of registered capacity. This corresponds to an 82.09% decrease from 2023 and a 58.80% decrease from 2024, largely due to the eventual commercial operation of plants that were previously undergoing testing and commissioning activities. The quarterly profile also shows a marked decline from 1,048.46 MW in the 1st quarter to 199.21 MW in the 3rd quarter, before a modest increase to 519.72 MW in the 4th quarter.

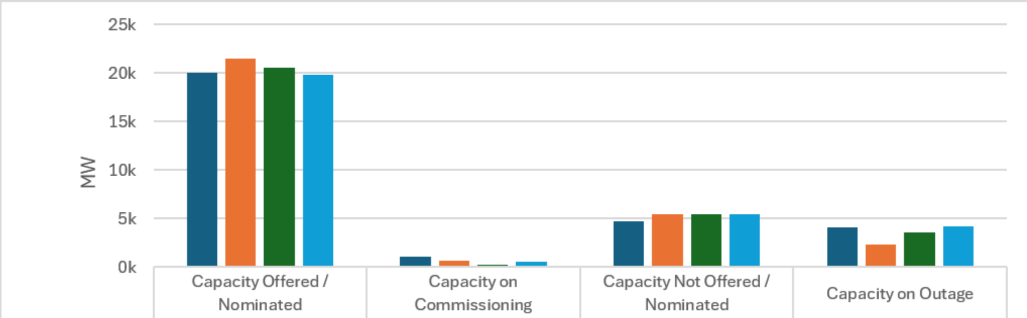
Capacity on Outage stood at 3,513.92 MW, equivalent to approximately 11.68% of registered capacity. This was 11.03% higher than in 2023 but 4.30% lower than in 2024. The quarterly data show that outage capacity was lowest in the 2nd quarter at 2,261.70 MW but increased again in the 3rd and 4th quarters, reaching 4,204.49 MW in the 4th quarter. This indicates that although outage levels improved compared with 2024 on an annual basis, plant outages remained a significant factor affecting available capacity during certain periods of 2025.

Overall, the 2025 capacity profile shows that while offered/nominated capacity increased year-on-year, the growth in capacity not offered/nominated and the persistence of outage capacity continued to limit the effective availability of registered capacity. The decline in capacity on commissioning is a positive development, as it indicates the transition of several plants from testing to commercial operation.




| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Capacity on Outage | 3,164.74 | 3,671.81 | 3,513.92 |
| Capacity on Commissioning | 3,366.53 | 1,463.45 | 602.98 |
| Capacity Not Offered / Nominated | 2,049.69 | 4,552.32 | 5,275.23 |
| Capacity Offered / Nominated | 17,755.89 | 18,897.85 | 20,434.46 |

**Figure 4: Average Capacity Profile – 2023 to 2025**




| | Capacity Offered / Nominated | Capacity on Commissioning | Capacity Not Offered / Nominated | Capacity on Outage |
|---|---|---|---|---|
| 1st Quarter | 19,997.59 | 1,048.46 | 4,749.39 | 4,117.93 |
| 2nd Quarter | 21,422.38 | 653.29 | 5,422.80 | 2,261.70 |
| 3rd Quarter | 20,516.25 | 199.21 | 5,471.33 | 3,515.08 |
| 4th Quarter | 19,790.62 | 519.72 | 5,451.75 | 4,204.49 |

**Figure 5: Average Capacity Profile per quarter - 2025**

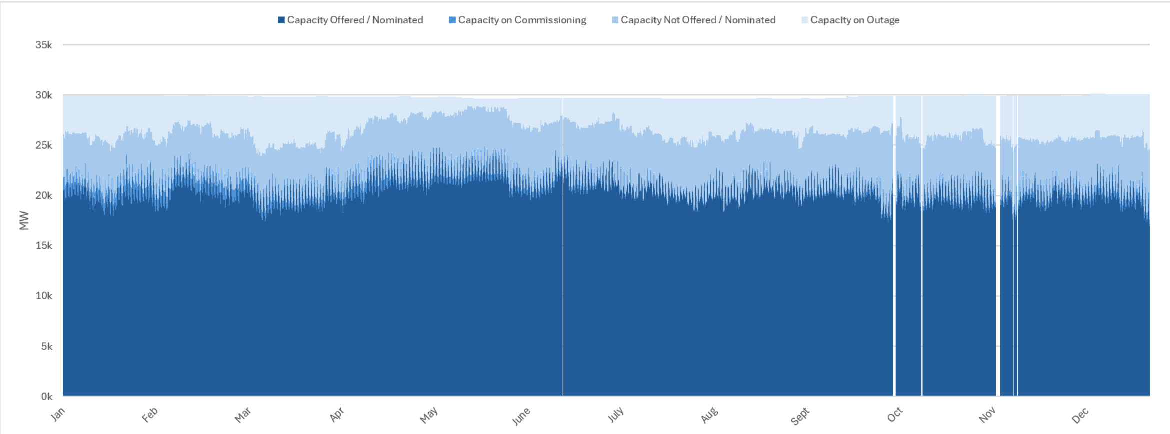



**Figure 6: Capacity Profile per interval – 2025**

*Note: Missing trading intervals were under Market Intervention and/or Market Suspension*

## iii. Capacity on Outage

Capacity on outage in 2025 peaked at approximately 6,004.5 MW on 02 March 2025, during the 1015h–1030h interval. March 2025 recorded one of the highest monthly average outage levels for the year, primarily due to the continuing outage of major coal facilities, including GNPower Mariveles Coal-Fired Power Plant Unit 2 (01MARVEL_G02), Masinloc Coal-Fired Thermal Power Plant Unit 1 (01MSINLO_G01), and GNPower Dinginin Coal Plant - Unit 1 (01GNPD_U01). The forced outage of QPPL Coal-Fired Power Plant (03QPPL_G01), which accounted for around 460 MW of unavailable coal capacity, further contributed to the elevated level during the period.

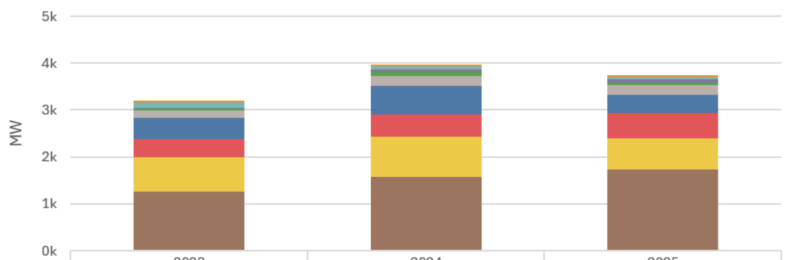
In contrast, the 2$^{nd}$ quarter recorded the lowest average outage level for the year at approximately 2,278 MW, reflecting improved availability following the resumption of operations across several plant types, although outages in battery storage and wind facilities remained. The lowest interval outage level was recorded on 10 May 2025 at approximately 781.2 MW.

## a. Capacity on Outage per Plant Type

An assessment of capacity on outage by plant type shows that coal plants continued to account for the largest share of outages in 2025, followed by natural gas and oil-based plants. This ranking has remained broadly consistent across the comparative years from 2023 to 2025, indicating that outages remained concentrated among major conventional generation technologies.

As shown in Figure 7, average coal capacity on outage increased from 1,265 MW in 2023 to 1,580 MW in 2024, and further to 1,727.10 MW in 2025. Natural gas outages declined from 847 MW in 2024 to 674.57 MW in 2025, although natural gas remained the second-largest contributor to outage capacity. Oil-based plants recorded a continued increase in outage capacity, rising from 385 MW in 2023 to 543.65 MW in 2025. In contrast, hydropower outages declined from 616 MW in 2024 to 383.77 MW in 2025.

Overall, total average capacity on outage decreased in 2025 compared with 2024, mainly due to lower outages from natural gas and hydropower plants; however, this was partly offset by higher outage levels from coal and oil-based facilities.




| | 2023 | 2024 | 2025 |
|---|---|---|---|
| SOLR | 28.00 | 37.00 | 37.39 |
| WIND | 130.00 | 82.00 | 57.28 |
| BAT | 20.00 | 43.00 | 59.97 |
| BIOF | 36.00 | 96.00 | 60.72 |
| GEO | 158.00 | 196.00 | 203.23 |
| HYD | 445.00 | 616.00 | 383.77 |
| OIL | 385.00 | 481.00 | 543.65 |
| NATG | 734.00 | 847.00 | 674.57 |
| COAL | 1,265.00 | 1,580.00 | 1,727.10 |

**Figure 7: Average Capacity on Outage by Plant Type - 2023 to 2025**

The 2025 per-interval outage profile in Figure 8 further shows that outage levels fluctuated throughout the year, with the lowest system-wide outage levels occurring during the 2nd quarter. Coal outages were highest during the 1st quarter, declined in the 2nd quarter, and increased again during the 3rd and 4th quarters. The increase in the 2nd half of the year was associated with outages of major coal plants, including Sual Coal-Fired Power Thermal Plant 1 (01SUAL_G01), Pulverized Coal Fired Power Plant Unit 1 (03CALACA_G01), Masinloc Coal-Fired Thermal Power Plant Unit 3 (01MSINLO_G03), GNPower Dinginin Coal Plant - Unit 1 (01GNPD_U01).

Natural gas plants also contributed significantly to outage levels, particularly in the 4th quarter. The increase was associated with outages of major gas facilities, including Batangas Combined Cycle Power Plant Unit 1 (03EERI_G01), Ilijan Natural Gas Combined-Cycle Power Plant 1 (03ILIJAN_G01), Ilijan Natural Gas Combined-Cycle Power Plant 2 (03ILIJAN_G02), Sta. Rita Natural Gas Power Plant 1 (03STA-RI_G01), Sta. Rita Natural Gas Power Plant 5 (03STA-RI_G05), and Sta. Rita Natural Gas Power Plant 6 (STA-RI_G06).This contributed to the higher outage levels observed toward the end of the year.

Overall, the outage profile indicates that the availability of large conventional generating units remained a key driver of system-wide outage levels in 2025. While the 2nd quarter showed a notable improvement in plant availability, the major coal and natural gas outages recurred in other quarters, contributing to elevated outage levels during those periods.

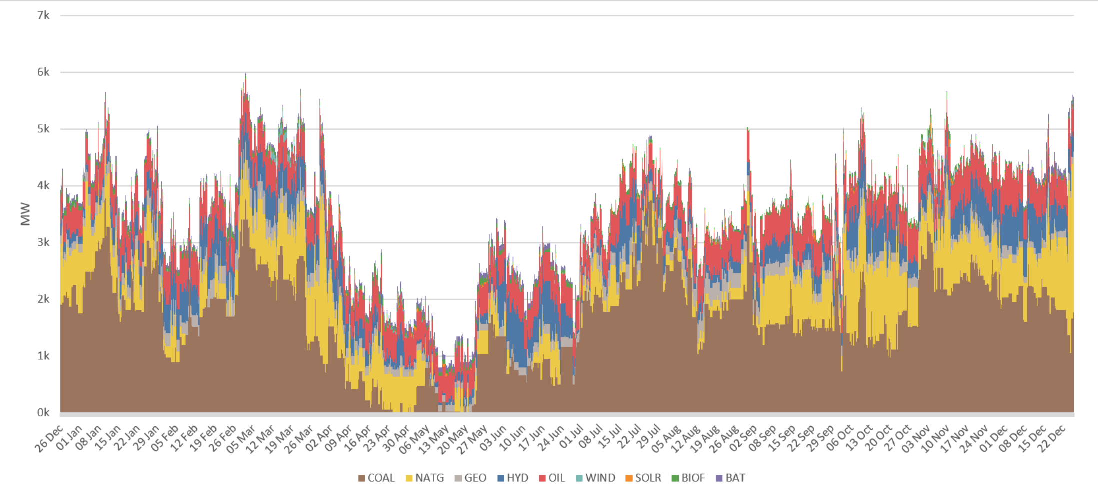



**Figure 8: Per Interval Capacity on Outage by Plant Type - 2025**

Looking at the outage rate per plant type, coal-fired plants recorded the highest average capacity on outage at 1,727.10 MW, reflecting the substantial amount of unavailable baseload capacity during the year. However, the corresponding outage rate of 14.19% indicates that, on average, approximately one-seventh of the registered coal plants was unavailable due to outages. While coal accounted for the largest outage volume in absolute terms, its outage rate was lower than those of oil, biofuel, and natural gas technologies.

Oil plants registered the highest outage rate of 19.57%, indicating that nearly one-fifth of the technology's registered capacity was unavailable on average during 2025. Although oil-based plants contributed a smaller average outage capacity than coal, the higher outage rate suggests comparatively lower operational availability within the oil-based plants.

Natural gas plants exhibited an outage rate of 14.81%, slightly higher than that of coal. Given the technology's role in providing mid-merit and peaking capacity, sustained outages could limit the system's ability to respond to variations in electricity demand.

Biofuel plants recorded an average capacity on outage of only 60.72 MW; however, their corresponding outage rate of 14.94% was higher than those of coal and natural gas. This indicates that, despite their relatively small contribution to total outage capacity, a comparatively larger proportion of registered biofuel capacity was unavailable during the year.

Overall, the results show that absolute outage capacity and outage rate provide complementary insights into generation reliability. While coal contributed the largest average outage capacity because of its substantial registered capacity, oil, biofuel, and natural gas exhibited higher outage rates, indicating that a larger proportion of their registered capacities was unavailable during the year.

**Table 4: Capacity-Based Outage Rate per Plant Type - 2025**

| Plant Type | Average Capacity on Outage (MW) | Registered Capacity (MW) | Outage Rate (%)[4] |
|---|---|---|---|
| COAL | 1,727.10 | 12,174.70 | 14.19% |
| NATURAL GAS | 674.57 | 4,554.50 | 14.81% |
| OIL | 543.65 | 2,778.50 | 19.57% |
| HYDRO | 383.77 | 3,783.80 | 10.14% |
| GEOTHERMAL | 203.23 | 1,725.20 | 11.78% |
| BIOFUEL | 60.72 | 406.30 | 14.94% |
| BATTERY | 59.97 | 668.70 | 8.97% |
| WIND | 57.28 | 506.10 | 11.32% |
| SOLAR | 37.39 | 3,496.00 | 1.07% |

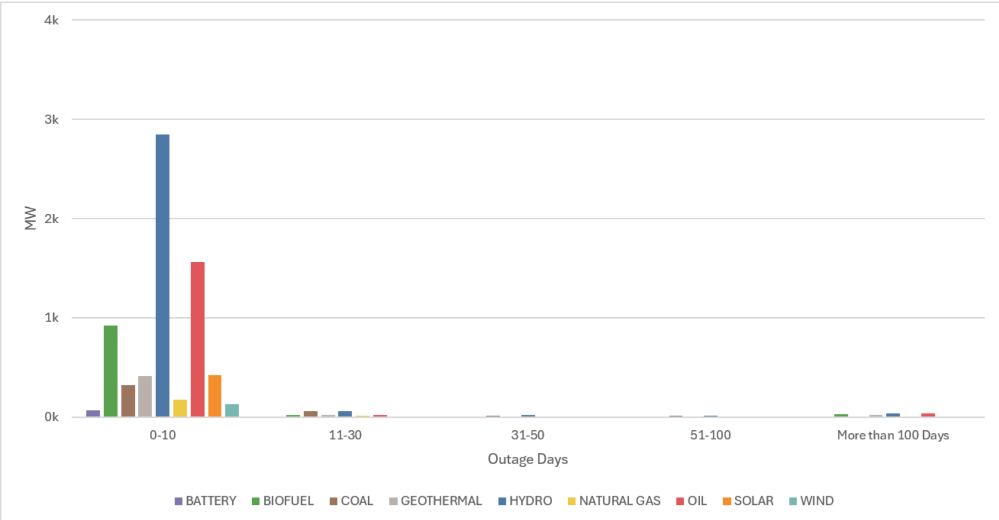
Figure 9 presents the count of outage events by plant type and outage duration for 2025. The majority of recorded outages were resolved within the 0–10 day duration bracket, accounted for almost all outage events across plant technologies. Hydropower plants registered the highest frequency of short-duration outages with 2,846 occurrences, followed by oil-based plants with 1,560 occurrences and biomass plants with 921 occurrences.

Extended outages of more than 30 days were relatively limited. Hydropower plants accounted for the highest number of prolonged outages with 51 recorded occurrences, followed by coal plants with 30 recorded occurrences. The low frequency of long-duration outages suggests that most outage incidents were addressed and returned to service within shorter timeframes. For coal plants, the prolonged outages included major units such as 01GNPD_U01, 01SUAL_G01, 03QPPL_G01, Pagbilao 3 Power Plant (03PAGBIL_G03), 01MARVEL_G02, 03CALACA_G01. For hydropower plants, prolonged outages included Kalayaan Pump Storage Power Plant Unit 2 (03KAL_G02). For Natural Gas Plants, these

[4] Outage Rate (%) = (Average Capacity on Outage (MW)/Total Registered Capacity (MW)) x 100%

included Batangas Combined Cycle Power Plant Unit 3 (03EERI_G03), Sta. Rita Natural Gas Power Plant 4 (03STA-RI_G04), 03STA-RI_G01, and 03ILIJAN_G01.

More than 94% of recorded outage events were completed within 10 days, indicating that outage durations in 2025 were generally short and that generating units were restored to service within a relatively brief period. This suggests that prolonged outages represented only a small fraction of the total outage events recorded during 2025.




| Plant Type | Outage Duration (Range in Days) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 0-10 | | 11-30 | | 31-50 | | 51-100 | | More than 100 Days | |
| | Frequency | # of Plants | Frequency | # of Plants | Frequency | # of Plants | Frequency | # of Plants | Frequency | # of Plants |
| BAT | 67 | 19 | 2 | 2 | | | 1 | 1 | 4 | 3 |
| BIOF | 923 | 31 | 21 | 16 | 4 | 4 | 6 | 6 | 28 | 20 |
| COAL | 325 | 61 | 62 | 43 | 13 | 13 | 12 | 10 | 8 | 7 |
| GEO | 415 | 25 | 21 | 11 | 5 | 4 | 2 | 2 | 22 | 7 |
| HYD | 2,848 | 94 | 57 | 42 | 18 | 12 | 16 | 12 | 34 | 27 |
| NATG | 176 | 14 | 16 | 6 | 1 | 1 | 3 | 3 | 4 | 3 |
| OIL | 1,560 | 113 | 25 | 24 | 6 | 5 | 3 | 3 | 35 | 21 |
| SOLR | 418 | 55 | 1 | 1 | | | 2 | 2 | 4 | 4 |
| WIND | 128 | 10 | | | | | 1 | 1 | 1 | 1 |

**Figure 9: Count of Outage Per Plant Type Per Duration – 2025**[5]

To further assess outage characteristics, the analysis examines the share of long-duration outages, defined as outages lasting more than 30 days, and short-duration outages, defined as outages lasting 30 days or less, across plant technologies, as presented in Figure 9. This complements the outage rate analysis by evaluating not only the extent of unavailable capacity but also the persistence of outages, thereby providing additional insights into generation reliability and the potential impact of prolonged outages on system adequacy.

Biofuel plants recorded the highest long-duration outage share at 36.72%, equivalent to 338.10 MW of outage capacity. Although the biofuel plants represent a relatively small portion of the country's registered generating capacity, more than one-third of their recorded outage capacity remained

[5] Outages with no recorded end date are assumed to be ongoing as of the end of the reporting period and are included in the analysis

unavailable for more than 30 days, indicating comparatively prolonged outage durations within the technology. These extended outages were commonly associated with fuel supply constraints or low supply of sugar cane, and other operational issues requiring longer restoration periods.

Coal-fired plants exhibited a long-duration outage share of 24.68%, with 6,749.20 MW of outage capacity extending beyond 30 days, the largest absolute long-duration outage capacity among all technologies. Given coal's significant contribution to the country's generation mix, prolonged outages in coal-fired units can substantially reduce available baseload capacity and have influence on overall system adequacy than outages in smaller-capacity technologies.

Solar plants demonstrated the lowest long-duration outage share at 8.57%, with 91.43% of outage capacity lasting 30 days or less. This indicates that outages affecting the solar plants were generally resolved within a shorter period, thereby minimizing prolonged capacity unavailability.

Overall, the results indicate that while biofuel, oil, and natural gas exhibited the highest relative shares of prolonged outages, coal contributed by far the largest volume of long-duration outage capacity in absolute terms. This distinction highlights the importance of evaluating both outage share and outage magnitude.

**Table 5: Outage Share per Plant Type in terms of Short and Long Duration**

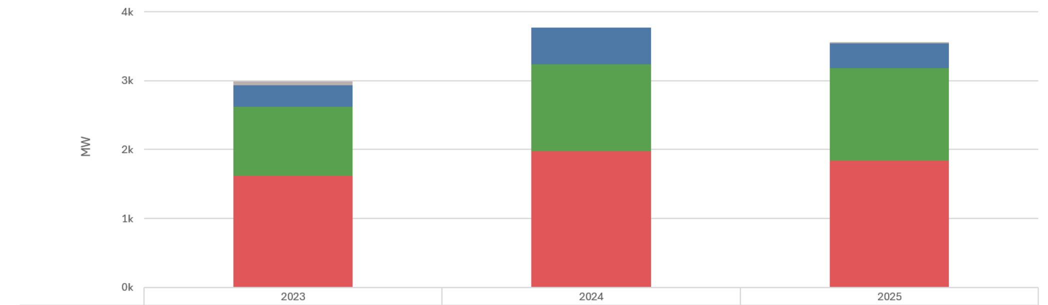
| Plant Type | Overall Total Capacity on Outage (MW) | Total Capacity on Outage (MW) (More than 30 Days) | Outage Share Outages > 30 Days(%) | Outage Share Outages ≤ 30 Days(%) |
|---|---|---|---|---|
| BAT | 788.40 | 180.00 | 22.83% | 77.17% |
| BIOFUEL | 920.80 | 338.10 | 36.72% | 63.28% |
| COAL | 27,342.40 | 6,749.20 | 24.68% | 75.32% |
| GEOTHERMAL | 1,391.30 | 254.70 | 18.31% | 81.69% |
| HYDRO | 7,021.12 | 1,472.19 | 20.97% | 79.03% |
| NATURAL GAS | 7,808.40 | 2,051.00 | 26.27% | 73.73% |
| OIL | 3,248.15 | 877.80 | 27.02% | 72.98% |
| SOLAR | 1,976.98 | 169.40 | 8.57% | 91.43% |
| WIND | 729.70 | 160.00 | 21.93% | 78.07% |

### b. Capacity on Outage per Category

In terms of average capacity on outage by category, planned outages increased to 1,338.14 MW in 2025, representing a 6.44% increase from the 2024 level. In contrast, the average capacity on forced and maintenance outages declined by 6.73% and 33.53%, respectively, indicating improved availability of generating units affected by these outage categories.

No deactivated shutdowns were recorded in 2024. However, in 2025, deactivated units accounted for an average outage capacity of 18.33 MW, reflecting the inclusion of generating units that were no longer available for commercial operation during the assessment period

Despite the year-on-year reduction in average forced outage capacity, forced outages continued to account for the largest share of outage capacity among all outage categories. This underscores the continued impact of unplanned generating unit outages on overall generation availability and system operations.




| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Deactivated Shutdown | 55.00 | | 18.33 |
| Maintenance | 311.00 | 536.53 | 356.66 |
| Planned | 1,005.00 | 1,257.17 | 1,338.14 |
| Forced | 1,619.00 | 1,974.94 | 1,841.98 |

**Figure 10: Yearly Average Capacity on Outage by Category, 2023 to 2025**

Figure 11 illustrates the capacity on outage per interval in 2025. Outage levels during the 3rd and 4th quarters were predominantly driven by forced and planned outages, with average forced outages peaking at 2,377.65 MW and planned outages reaching 1,736.10 MW. These periods reflect the combined effects of scheduled maintenance activities and unplanned generating unit outages.

The 1st quarter recorded the second-highest average planned outage capacity and the highest average maintenance outage capacity. Pursuant to the Department of Energy (DOE) policy, planned and maintenance outages are generally prohibited during the summer season, except for hydroelectric generating units, to preserve adequate operating reserves and mitigate the risk of thin supply margins during periods of high electricity demand.

The highest level of forced outage in 2025 was recorded between 1 October and 10 October, when average forced outage capacity ranged from 3,771.45 MW to 3,882.65 MW. The elevated outage levels were primarily attributed to the multiple transmission line and generating unit trips following the earthquakes that struck Cebu on 1 October and Davao on 10 October. These events resulted in widespread generation outages and underscored the vulnerability of power system operations to major geophysical disturbances

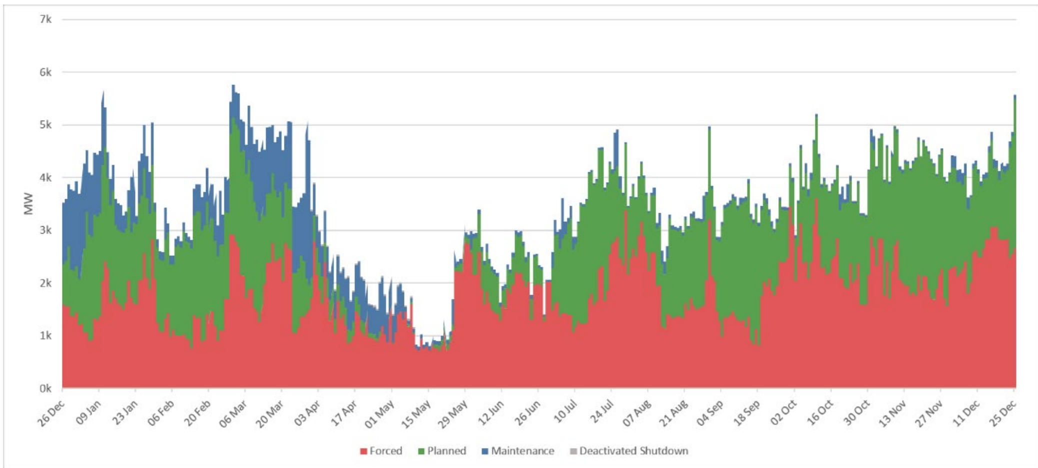
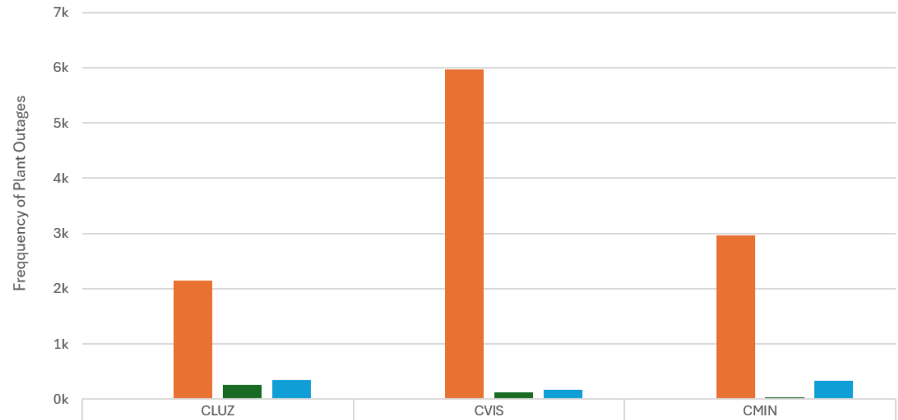



**Figure 11: Average Capacity on Outage by Category per Interval - 2025**

Figure 12 presents the frequency of recorded outage events by outage category for each grid in 2025. The analysis reflects the total number of outage occurrences recorded during the assessment period and does not represent the number of unique generating units affected. Accordingly, a generating unit may contribute multiple outage events depending on the number of occurrences recorded throughout the year.

Across all grids, forced outages accounted for the highest frequency of outage occurrences, indicating that unplanned events remained the most prevalent cause of generating unit unavailability. This highlights the continued operational impact of unexpected equipment failures, system disturbances, and other events requiring immediate unit shutdown or derating.

The Visayas grid recorded the highest number of outage occurrences, with 5,966 forced outage events, significantly exceeding the frequency observed in the Luzon and Mindanao grids. This indicates a higher incidence of unplanned generation interruptions in the Visayas during the assessment period.




| | CLUZ | CVIS | CMIN |
|---|---|---|---|
| Deactivated Shutdown | | 13 | |
| Forced Outage | 2,142 | 5,966 | 2,967 |
| Maintenance Outage | 260 | 119 | 35 |
| Planned Outage | 354 | 171 | 337 |

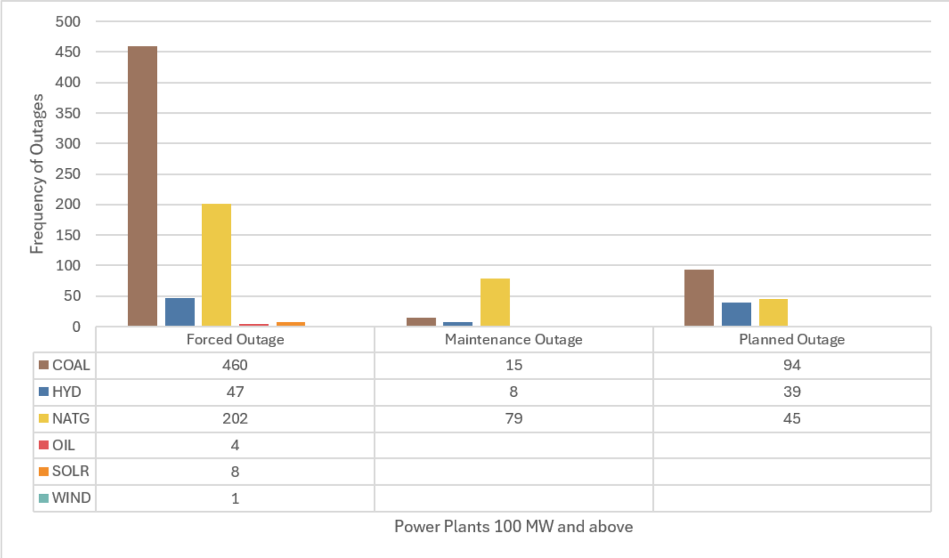
**Figure 12: Frequency of Outages per Category per Region – 2025**

Overall, the outage frequency profile demonstrates that forced outages remain the primary driver of generation interruptions across all grids, while planned and maintenance outages represented scheduled activities of generating units.

Figure 13 presents the frequency of recorded outage events by outage category disaggregated by generation technology for power plants with capacities of 100 MW and above.

The outage distribution was heavily skewed toward forced outages, which consistently registered the highest frequency across the covered generation technologies. Coal-fired plants exhibit the most pronounced contribution, with 460 forced outage events, followed by natural gas at 202 and hydropower plants at 47. This indicates that unplanned outages remain the dominant driver of generating unit unavailability.

Maintenance and planned outage occurrences were comparatively lower than forced outages, with natural gas plants recording the highest maintenance outage frequency at 79 occurrences, while coal-fired plants recorded the highest planned outage frequency at 94 occurrences.




| | COAL | | HYDRO | | NATURAL GAS | | GEOTHERMAL | | SOLAR | | WIND | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Outage Category | Frequency | # Plants | Frequency | # Plants | Frequency | # Plants | Frequency | # Plants | Frequency | # Plants | Frequency | # Plants |
| Forced Outage | 460 | 50 | 47 | 7 | 202 | 12 | 4 | 2 | 8 | 1 | 1 | 1 |
| Maintenance Outage | 15 | 8 | 8 | 4 | 79 | 11 | - | - | - | - | - | - |
| Planned Outage | 94 | 36 | 39 | 7 | 45 | 11 | - | - | - | - | - | - |

**Figure 13: Frequency of Outage per Plant Type with 100 MW and above Capacities**

## iv. Generation Mix

For 2025, coal-fired plants remained the dominant source of grid generation, contributing more than half of total generation in every quarter, with a quarterly share ranging from 55% to 59%. This is higher than coal's approximate 40.5% share in registered capacity, indicating that coal plants were utilized more intensively than their capacity share would suggest. This points to the continued role of coal as a baseload resource in meeting system demand.

A similar, though less pronounced, pattern was observed for natural gas plants. Their quarterly generation share remained material at around 17% to 20%, which appears higher than their share in registered capacity. This suggests that natural gas continued to provide an important supply source.

Taken together, coal and natural gas accounted for roughly 70% or more of quarterly generation in 2025. This indicates that the grid remained heavily dependent on these generation despite the recorded outages from these plant types during the year. The outage data therefore does not necessarily imply reduced system reliance; rather, it may indicate that available coal and gas units were still heavily dispatched when not on outage.

In contrast, renewable energy resources contributed 25.49% of total generation in 2025. While this represents a meaningful contribution, it remains below the DOE's reference target of 35% renewable energy share in the power generation mix by 2030. The DOE's Power Development Plan 2023–2050 adopts a national RE power generation mix target of 35% by 2030 and 50% by 2040 as the reference scenario.

Compared to 2024, the 2025 generation mix shows a clear strengthening of coal's dominance across most quarters, particularly evident in the 1st Quarter, rising from 55.1% to 59.1%, 2nd Quarter, rising from 59.1% to 63.0%, and 4th Quarter rising from 55.4% to 59.0%, with only Q3 reflecting a notable decline 53.3% from 2024's higher baseline. This suggests that coal dispatch became more pronounced in 2025 overall, reinforcing its role as the primary baseload source despite variability in certain periods.

Natural gas, on the other hand, exhibited a mixed but generally softer profile in 2025 relative to 2024, declining in several quarters such as 1st Quarter from 17.5% to 15.4%, 2nd Quarter 17.6% to 16.6%, and 3rd Quarter 17.1% to 13.7%, with a partial offset observed in the 3rd Quarter 19.9% to 15.1%. This indicates that while gas remained a key contributor, some of its generation share may have been displaced.

In aggregate, the year-on-year comparison indicates that the 2025 grid became slightly more reliant on coal while experiencing a mild reduction in natural gas share and only limited gains in renewable penetration. This dynamic underscores a continued dependence on thermal generation, with limited progress toward diversifying the generation mix in line with long-term renewable energy targets.

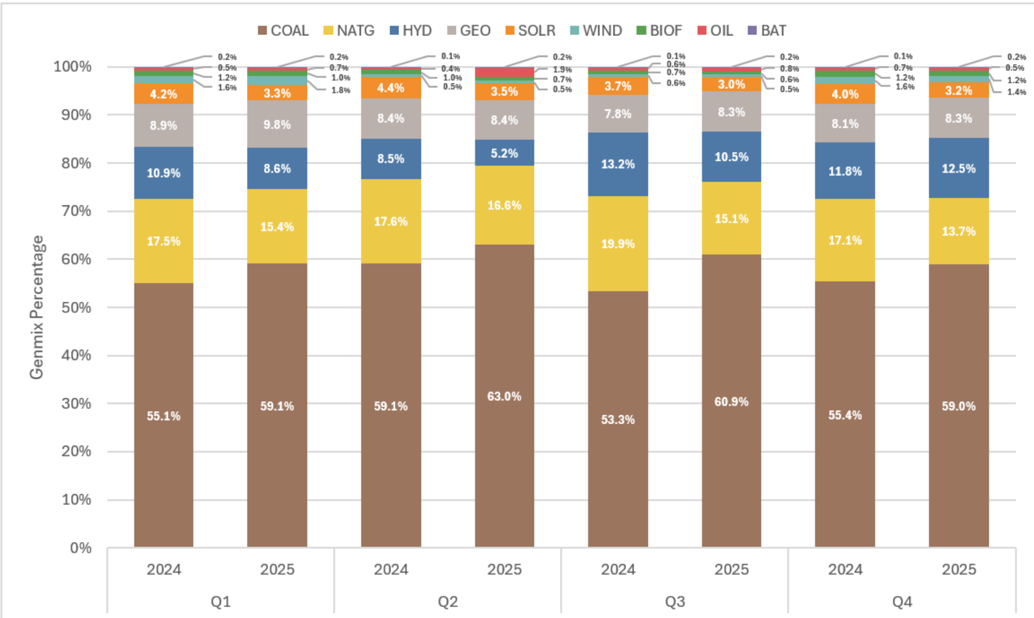



**Figure 14: Generation Mix per Quarter – 2024 to 2025**

### v. Capacity factor[6]

The 2025 capacity factor profile shows a mixed year-on-year movement across technologies. Coal, geothermal, solar, oil, and battery recorded lower capacity factors compared with 2024, while natural gas, hydro, biofuel, and wind showed improvements. This suggests that changes in plant utilization were not uniform across the fleet and were likely influenced by a combination of various factors.

Coal remained one of the highest-utilization technologies despite declining from 65% in 2024 to 60.74% in 2025, equivalent to a reduction of about 4.26%. This indicates a moderation in coal plant utilization but still reflects its continued role as a major baseload and energy-supplying resource in the grid. Geothermal posted the highest 2025 capacity factor at 63.36%, only slightly lower than its 66.00% level in 2024. This supports the observation that geothermal remained one of the most stable baseload technologies, consistent with its priority/preferential dispatch treatment and generally continuous operating profile.

Natural gas improved from 51% in 2024 to 53.04% in 2025, indicating slightly higher utilization during the year. This may reflect the continued need for dispatchable and flexible capacity, particularly during periods of renewable variability, outages, or higher system demand.

The strongest year-on-year improvements were recorded by hydro and biofuel. Hydro increased from 32.00% to 39.29%, while biofuel increased from 27.00% to 33.55%. The increase in hydro capacity factor suggests improved water availability and/or higher dispatch of hydro units during the year. Meanwhile, the improvement in biofuel indicates stronger utilization relative to its available capacity.

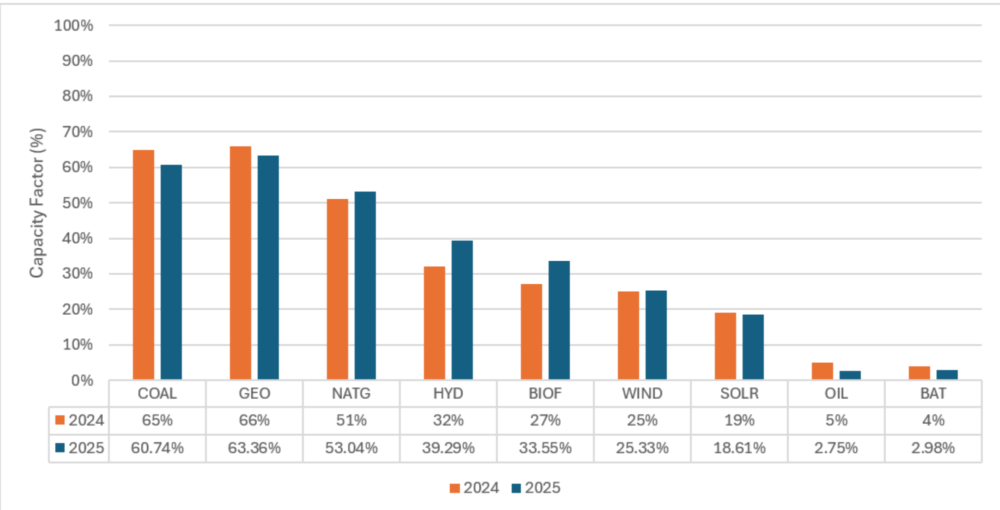



**Figure 15: Capacity Factor per Plant Type – 2024 to 2025**

[6] Capacity factor is the ratio between the total metered quantity and the total registered capacity.

Solar and wind remained in the lower-to-mid capacity factor range, consistent with the intermittent and resource-dependent nature of these technologies. Wind slightly improved from 25.00% to 25.33%, while solar marginally declined from 19.00% to 18.61%. These changes are relatively small and should be interpreted as broadly stable year-on-year performance. Oil and battery facilities recorded the lowest capacity factors in 2025 at 2.75% and 2.98%, respectively. This does not necessarily indicate poor performance. Rather, it reflects their limited role in bulk energy production.

Hydropower plants consistently recorded higher capacity factors than solar facilities throughout 2025. Hydro capacity factors were relatively moderate during the first half of the year but increased sharply beginning in July 2025, reaching elevated levels during August to October. This trend is consistent with the timing of the southwest monsoon season. PAGASA declared the start of the southwest monsoon on 30 May 2025, noting the persistence of low-level southwesterly winds over parts of Luzon[7]. The elevated hydro performance during August to October may be associated with wetter monsoon conditions and improved water availability.

In contrast, solar capacity factors were highest during the dry-season months of March to May, reaching approximately 22% to 24%. This pattern is consistent with stronger solar irradiance and relatively clearer sky conditions during the dry and warm season. In contrast, solar capacity factors softened during the wetter months, likely reflecting increased cloud cover and rainfall during the monsoon period.

The opposing seasonal profiles of hydro and solar highlight their complementary role within the renewable energy mix. Solar output is generally stronger during dry months, while hydro output improves during wetter periods when reservoir inflows and river discharges increase. This complementary can help stabilize renewable energy contribution across different climatic periods.

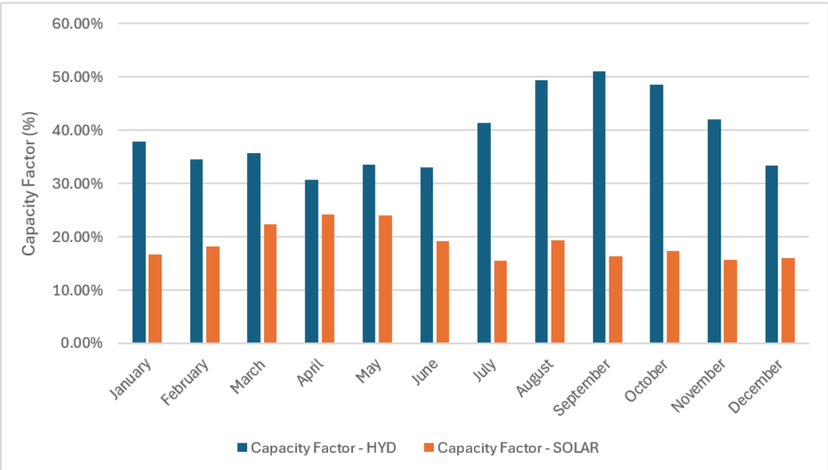



**Figure 16:Capacity Factor for Hydro and Solar – 2025**

[7] https://www.pagasa.dost.gov.ph/press-release/185

## B. Demand

Figure 17 presents the annual average demand profile and effective supply from 2023 to 2025. System demand increased from 12,858 MW in 2023 to 13,904 MW in 2024, representing a year-on-year growth of 8.13%. In 2025, demand reached 13,963 MW, reflecting only a marginal increase of 0.43% from the previous year.

In contrast, effective supply continued to expand at a faster pace. Effective supply increased from 16,369 MW in 2024 to 17,969 MW in 2025, equivalent to a 9.78% increase. As a result, the supply margin widened from 2,465 MW in 2024 to 4,006 MW in 2025. This indicates an improvement in the average supply-demand balance and suggests a stronger capacity adequacy position compared with the previous year.

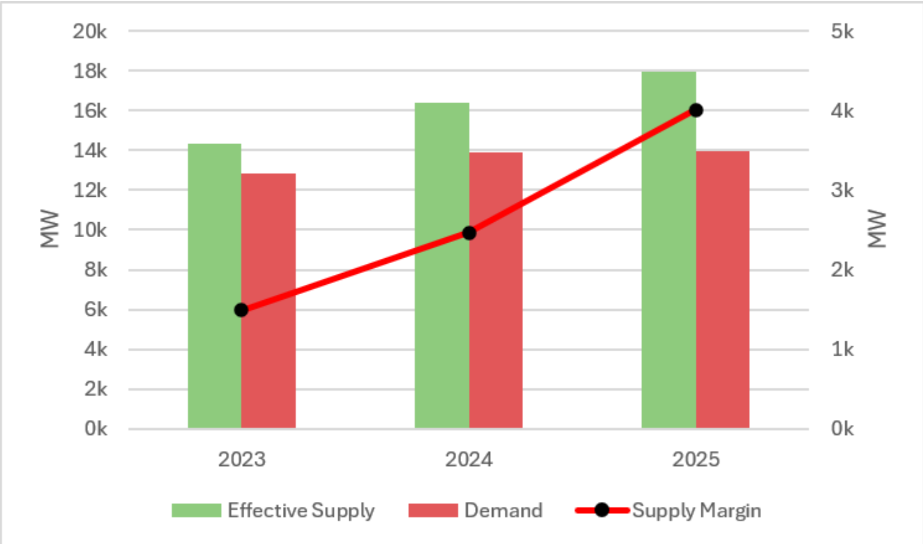



**Figure 17: Demand Profile - 2023 to 2025**

Figure 18 presents the monthly average effective supply, system demand, and demand plus reserve requirement for 2025. On a monthly average basis, effective supply consistently exceeded both system demand and the demand plus reserve requirement. This indicates that the system generally maintained sufficient available capacity to meet load and reserve requirements during the year.

System demand exhibited a pronounced seasonal pattern, increasing from 12,645 MW in January to a peak of 15,345 MW in May, before gradually declining during the latter half of the year. This rise coincided with the dry season, when higher temperatures typically increase electricity consumption, particularly due to cooling demand. After the May 2025 peak, demand declined to 14,707 MW in June 2025 and generally ranged from around 13,652 MW to 14,232 MW during the remainder of the year.

The tightest recorded margin occurred in May 2025, when the difference between the effective supply and demand plus reserve requirements narrowed to approximately 2,046 MW. This reflected relatively tighter system conditions during the peak demand period. Conversely, wider margins were observed during the cooler months, particularly in January and February, when demand levels were comparatively lower. Despite these seasonal fluctuations, effective supply remained sufficient to cover both system demand and reserve requirements in all months of 2025.

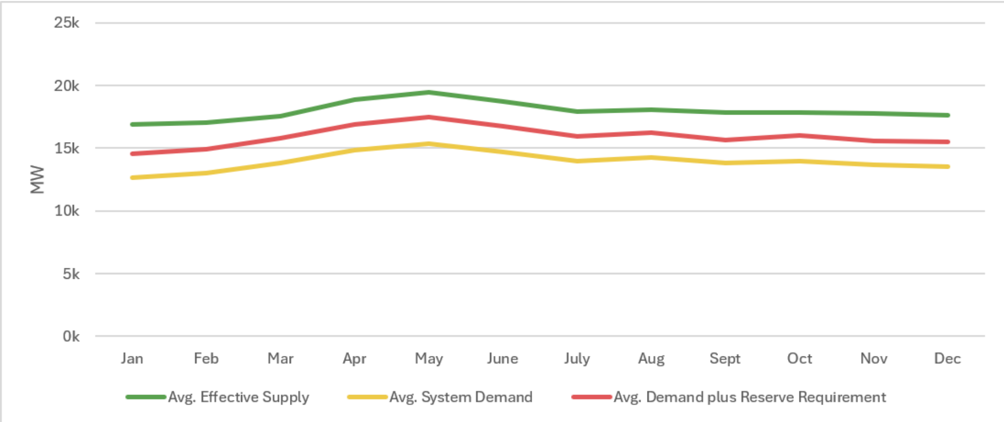



**Figure 18: Monthly Demand Profile – 2025**

Over the three-year period, demand grew by 8.59%, while effective supply expanded by 25.23%, indicating that supply additions outpaced demand growth. This suggests an improvement in the overall reserve position and a greater capability of the power system to meet load requirements. The increase in available capacity relative to demand may contribute to improved reliability and a reduced risk of supply shortages, particularly during periods of high system demand. However, this does not eliminate the possibility of Yellow Alert conditions, as available reserves may still fall below required levels due to outages, deratings, maintenance activities, transmission constraints, or other system conditions. The Yellow Alert occurrences are listed below, with further details provided in the *Annex B: Yellow Alert Occurrences*.

**Table 6: Grid Alerts - 2025**

| Region | Alert | Date/s |
|---|---|---|
| Luzon | Yellow Alert | • March 5, 2025 |
| Visayas | | • August 1, 4, 5, and 6, 2025<br>• October 1, 2025<br>• November 19 and 20, 2025<br>• December 11, 2025 |
| Mindanao | | • August 1, 2025 |

Figures 19-21 shows the regional demand profile for 2025. The per region graphs shows the supply margin situation that led to the issuances of the Yellow alerts as stated in Table 2.

The occurrence of Yellow Alerts was primarily associated with periods of increased demand coupled with reduced generation availability arising from planned and forced outages of generating units. Although effective supply remained sufficient to meet actual demand, the combination of elevated demand and reduced available generation resulted in tighter operating conditions.

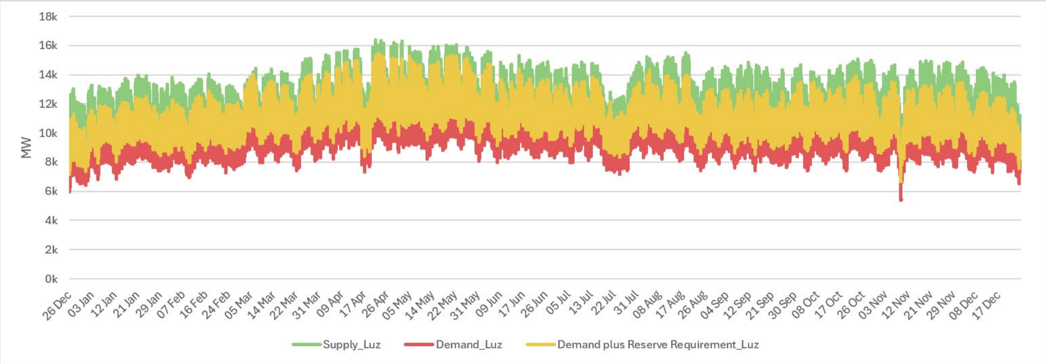



**Figure 19: Luzon Demand Profile – 2025**

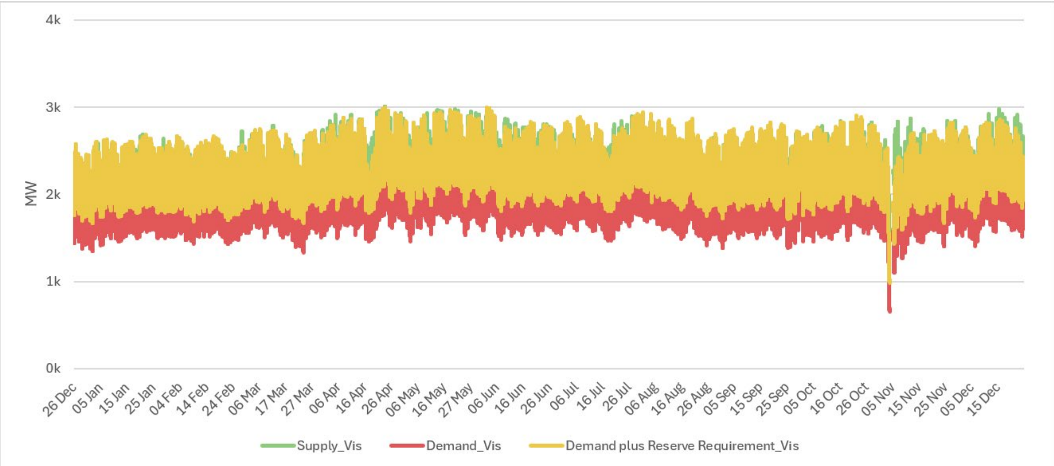



**Figure 20: Visayas Demand Profile – 2025**

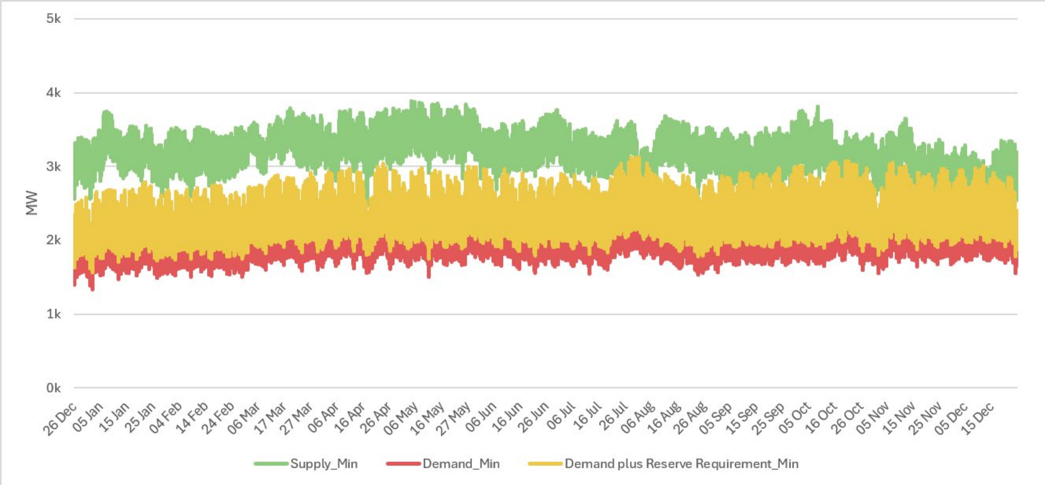



**Figure 21: Mindanao Demand Profile – 2025**

Based on the interval-level supply and demand profile for 2025, noticeable reductions in both effective supply and system demand were observed during portions of 3rd and 4th quarter. For 4th quarter, these declines appear to be associated with major system disturbances, including the effects of Typhoons Tino and Uwan, which resulted in power interruptions and market intervention/suspension events in the WESM. In addition, seismic events may have contributed to localized system disruptions, particularly the 30 September 2025 offshore Northern Cebu earthquake and the 10 October 2025 offshore Davao Oriental earthquake.

Despite intermittent dips during the year, 2nd quarter recorded the highest average system demand at approximately 14,970 MW. This increase is consistent with seasonal demand behavior, as April and May fall within the hot-dry season, when electricity consumption typically rises due to higher cooling requirements. The highest recorded system demand reached 19,052 MW during the 23 April 2025, 14:40h trading interval.

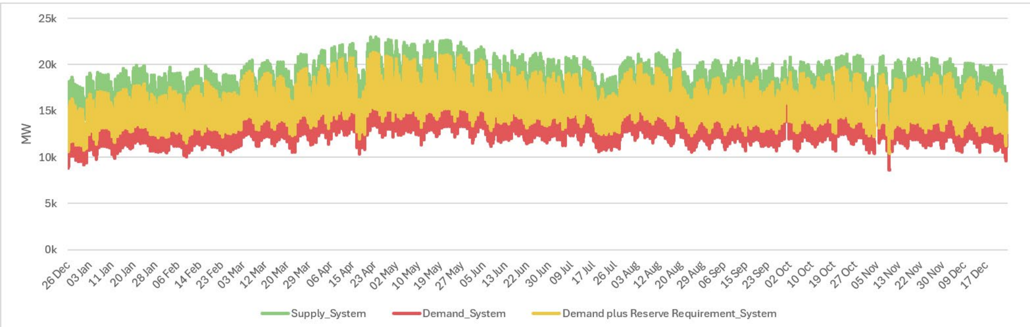



**Figure 22: System Demand Profile – 2025**

The 24-hour demand profile reflects typical daily electricity consumption patterns, as shown in Figure 23. Average demand was lowest during the early morning hours, particularly from 0400h to 0700h, when demand remained at around 11,970.76 MW or lower. Demand then showed a steady increase beginning at around 0800h, consistent with the start of daytime commercial, industrial, and institutional activities.

Peak demand occurred between 1400h and 1600h, coinciding with sustained daytime economic activity and higher cooling requirements during the afternoon period. Demand slightly moderated in the early evening, particularly around 1700h to 1800h, before increasing again at around 1900h as evening residential demand began to rise. Thereafter, demand gradually declined toward midnight. This pattern demonstrates the relationship between system load behavior and daily socio-economic activity.

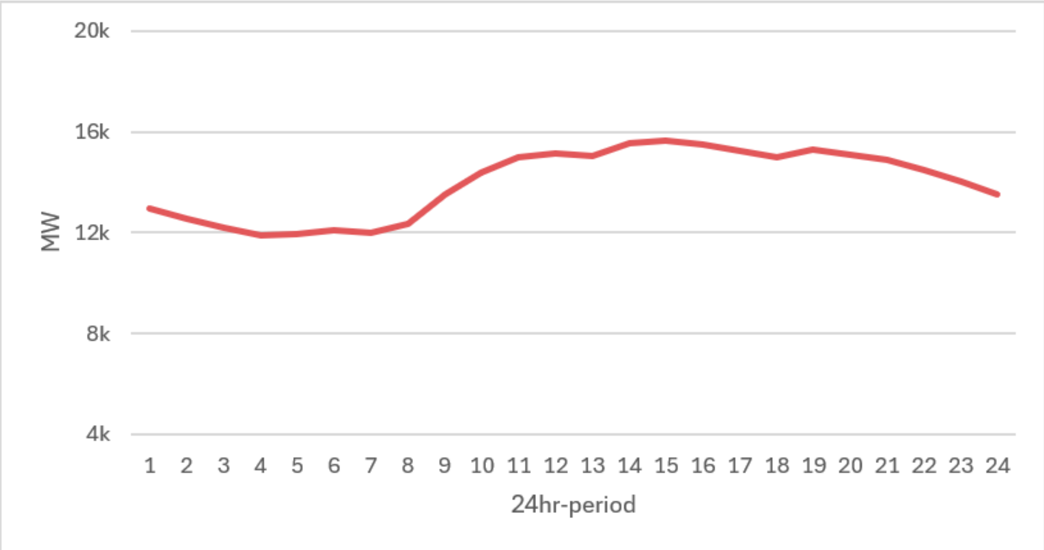



**Figure 23: 24-Hour Average System Demand – 2025**

## C. Price

### i. Load Weighted Average Price (LWAP)

The year-on-year comparison of the Load-Weighted Average Price (LWAP) shows a decrease from PHP 5,583/MWh in 2024 to PHP 3,981.72/MWh in 2025, equivalent to a reduction of approximately 28.68%. This decline suggests relatively improved supply conditions and reduced market tightness in 2025 compared with the previous year, although price movements may also have been influenced by other factors such as demand levels, outage conditions, generation mix, and offer behavior.

Figure 24 presents the monthly LWAP for 2025 compared with 2024. The average monthly LWAP in 2025 generally trended lower than in 2024, particularly during the first eight months of the year. Prices were notably lower in January, February, and April to September, indicating relatively more favorable market conditions during most of the period. However, prices in October and December 2025 were higher than the corresponding months in 2024, suggesting that market conditions tightened during certain periods despite the overall year-on-year decline.

The changes in LWAP observed between 2024 and 2025 can also be linked to the use of pre-determined pricing mechanisms, including Administered Prices (AP) imposed during market interventions or suspension events, as well as the Secondary Price Cap (SPC). During these periods, market prices may not fully reflect the underlying cost of electricity or prevailing supply conditions, potentially distorting price signals. A more detailed discussion on the application and effects of AP and SPC is presented in the succeeding section of this report.

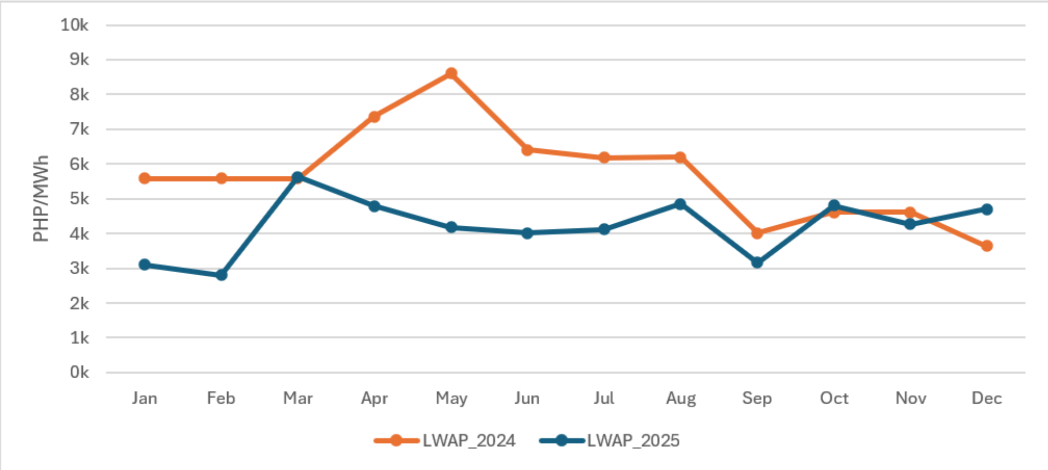



**Figure 24: Average LWAP - 2024 to 2025**

Table 7 presents the Spearman rank correlation[8] results, which provide a non-parametric assessment of the monotonic relationships among LWAP, Supply, Demand, Outage, and the Residual Supply Index (RSI). Since Spearman correlation is based on ranked values, the coefficients indicate the extent to which variables move together in a consistent direction, but they should not be interpreted as evidence of causation.

A dominant feature of the results is the near-perfect positive correlation between Supply and Demand, with a coefficient of $\rho = 0.977$. This indicates that the two variables moved closely together over the observation period. This relationship may reflect the tendency of available or scheduled supply to increase during periods of higher demand and decrease during periods of lower demand. However, this should not be interpreted as direct evidence that capacity expansion responded immediately to demand growth, since the correlation reflects co-movement rather than causation

LWAP shows a moderate positive correlation with Demand, with $\rho = 0.580$, suggesting that prices tended to increase during periods of higher demand. This result is consistent with market expectations, as higher demand periods are often associated with tighter market conditions and increased price pressure.

[8] https://statistics.laerd.com/statistical-guides/spearmans-rank-order-correlation-statistical-guide.php

LWAP also shows a moderate positive correlation with Supply, with ρ = 0.502. This relationship should be interpreted cautiously because Supply and Demand are highly correlated. The positive association between LWAP and Supply may therefore reflect periods in which higher supply was scheduled, dispatched, or made available in response to higher demand, rather than indicating that higher supply independently increased prices

The RSI shows a moderate negative correlation with LWAP, with ρ = -0.500. This is consistent with market expectations, as lower RSI values generally indicate tighter residual supply conditions and reduced competitive pressure, which may be associated with higher market prices. Conversely, higher RSI values suggest a more comfortable supply position and may correspond with lower prices. RSI is also negatively correlated with Demand, with ρ = -0.506, indicating that higher demand periods were generally associated with lower residual supply conditions and therefore tighter market conditions.

Outage levels exhibit relatively weak correlations with the other variables, including LWAP with ρ = 0.233, Supply with ρ = -0.108, Demand with ρ = -0.077, and RSI with ρ = -0.095. These weak relationships suggest that, over the period covered, outages were not strongly aligned with broad market-wide movements in price, supply, demand, or residual supply conditions. However, this does not necessarily mean that outages had no market impact. Rather, their effects may have been localized, episodic, or more visible in more granular interval-level data than in the aggregated correlation structure.

Overall, the correlation results indicate that price movements were more closely associated with demand and residual supply conditions than with outages. The strong Supply–Demand relationship suggests close co-movement between these two variables, while the negative relationship between RSI and LWAP supports the interpretation that tighter market conditions were associated with higher prices. Nonetheless, the results should be interpreted as descriptive evidence of monotonic association and not as proof of causal relationships among the variables.

**Table 7: Spearman Rank Correlation Table**

| Spearman Correlation | LWAP | Supply | Demand | Outage | RSI |
|---|---|---|---|---|---|
| **LWAP** | 1 | 0.50168 | 0.580485 | 0.233007 | -0.50039 |
| **Supply** | 0.50168 | 1 | 0.977294 | -0.10762 | -0.38282 |
| **Demand** | 0.580485 | 0.977294 | 1 | -0.07678 | -0.50582 |
| **Outage** | 0.233007 | -0.10762 | -0.07678 | 1 | -0.09546 |
| **RSI** | -0.50039 | -0.38282 | -0.50582 | -0.09546 | 1 |

On a per-interval basis in 2025, LWAP exhibited recurring price spikes despite the lower resulting annual LWAP. The interval-level trend shows that high-price events were not confined to a single period, although more frequent and sustained episodes appear during the summer months and selected periods in the second half of the year. This pattern is consistent with periods of tighter market conditions, which may be associated with higher demand during warmer weather conditions.

The highest recorded LWAP occurred on 27 March 2025 at the 1825h trading interval, reaching PHP51,759.75/MWh. During this interval, the system was relatively tight, with a supply margin of 338.56 MW, demand plus reserve requirement of 18,726.17 MW, and outage level of 4,241.1 MW. These conditions indicate that the price spike coincided with limited available supply relative to system requirements.

On the same trading day, 29 price spikes were recorded. Of these, one (1) price spike affected the whole system, while 28 price spikes affected both the Luzon and Visayas regions. During the Luzon-Visayas price spikes, the HVDC link from Mindanao to Visayas reached its maximum transfer limit of 450 MW, resulting in price separation in Mindanao during the incident, except at the 1555h trading interval.

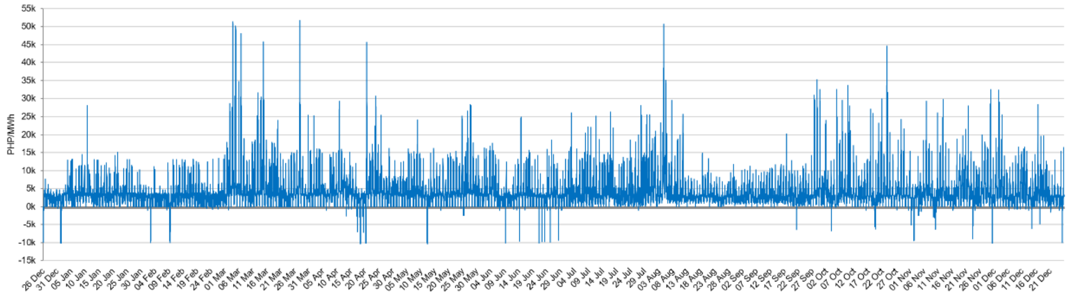



**Figure 25: Per Interval LWAP - 2025**

## ii. Price Distribution

The price distribution also shows a clear downward shift in market price concentration over the period. In 2023, prices were predominantly concentrated in the PHP 5,000/MWh to PHP 10,000/MWh range, whereas in 2024 and 2025 the largest share of intervals shifted to the lower PHP 0/MWh to PHP 5,000/MWh range. This indicates that the lower price environment observed in 2025 was not only reflected in the resulting LWAP, but also in the broader interval-level price distribution.

A notable decline is observed in the PHP 5,000/MWh to PHP 10,000/MWh price band, which decreased from 2023 to 2024 and further decline in 2025. At the same time, intervals priced at PHP 0/MWh and below increased from 2023 to 2025. This suggests a greater frequency of lower price intervals in 2025, which may have contributed to the lower annual LWAP.

However, the presence of intervals above PHP 10,000/MWh indicates that price spikes and high-price events continued to occur despite the overall shift toward lower price bands. Therefore, the 2025 distribution suggests a market characterized by generally lower prices, but with persistent interval-level volatility and occasional high-price outcomes.

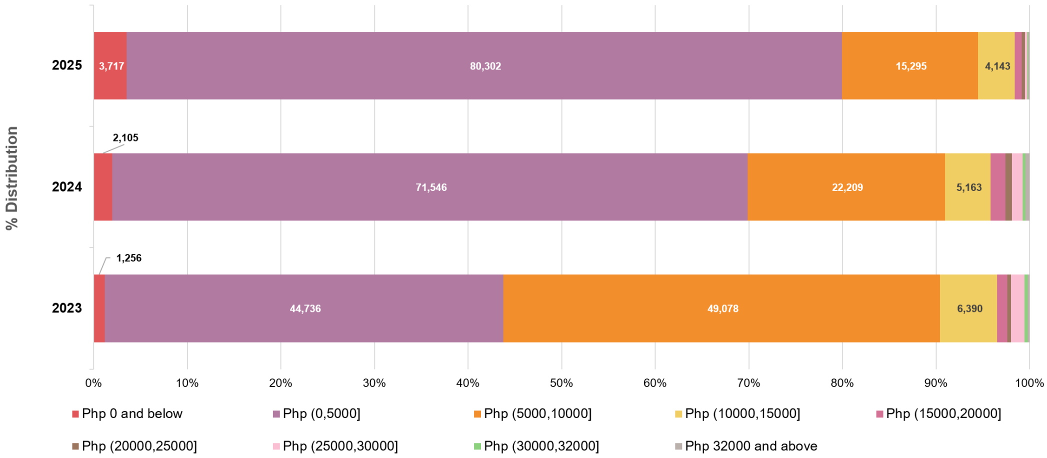



**Figure 26: LWAP Distribution - 2023 to 2025**

### iii. Pricing Conditions

The pricing condition distribution shows that the majority of trading intervals in 2025 were settled under normal pricing conditions across all regions. Normal pricing accounted for 99,022 intervals, or 94.20%, in Luzon; 98,295 intervals, or 93.51%, in Visayas; and 99,070 intervals, or 94.24%, in Mindanao. This represents an improvement from 2024, when normal pricing conditions accounted for 86.80% in Luzon, 86.45% in Visayas, and 87.91% in Mindanao. The increase in the share of normal pricing intervals indicates that fewer intervals were subject to pricing adjustments, corrections, or administrative pricing mechanisms in 2025, as follows:

#### a. Price Substitution Methodology (PSM)[9]

Among the three (3) major grids, all regions experienced a decreased in PSM imposition in 2025 compared to 2024. Luzon recorded 2,169 intervals under PSM, or 2.06%, down from 3,266 intervals, or 3.10%, in 2024. Visayas recorded 1,994 intervals, or 1.90%, down from 2,992 intervals, or 2.84%, while Mindanao recorded 1,992 intervals, or 1.89%, down from 3,027 intervals, or 2.87%. This indicates a broad reduction in the frequency of intervals requiring price substitution across all regions. Table 8 provides the top 10 network lines tagged as congested. Further, these congestions of lines/equipment triggered the imposition of the PSM.

[9] Section 6.2.5 of the Price Determination Methodology provides the price substitution methodology shall be implemented in all the regions where the WESM is in operation. In cases where a region/s has no interconnection with other regions, or has no exchange of power with other regions, this region/s shall be separately assessed for the application of the price substitution methodology.

**Table 8: Top 10 Congested Lines/Equipment - 2025**

| Line ID | Line/Equipment Name | Frequency of Congestion |
|---|---|---|
| 5DAAN_4TAB2 | Daanbantayan-Tabango 230 kV Line 2 | 1,980 |
| DASMA_CORR | Dasmarinas Corridor | 759 |
| 1MEXI_1HER2 | Mexico-Hermosa 230 kV Line 2 | 711 |
| LEYTE_TO_CEBU | Leyte-Cebu Transmission Line | 709 |
| 2ZAPOTE_TR4 | Zapote Substation Transformer 4 | 529 |
| 5COMPST_TR4 | Compostela Substation Transformer 4 | 420 |
| 4MAAS_7UBA1 | Maasin-Ubay 138 kV Line 1 | 364 |
| 3DASMA_TR3 | Dasmarinas Substation Transformer 3 | 266 |
| 1MEXI_1HER1 | Mexico-Hermosa 230 kV Line 1 | 192 |
| 1BAUA_1LAT1 | Bauang-Latrini 230 kV Line 1 | 159 |

### b. Administered Price (AP)

The Market Intervention events in 2025 consisted of both Market Operator-initiated and System Operator-initiated interventions. *Annex C: Market Intervention and Market Suspension List* summarizes the Market Intervention and Market Suspension events during the year. These included intervals affected by combined MO- and SO-initiated Market Interventions, as well as intervals affected by Market Suspensions declared by the ERC. The Market Suspension events were associated with system disturbances and calamity-related conditions, including the earthquake affecting the Bohol and Leyte-Samar sub-grids and Typhoon Tino, which affected the Visayas Region.

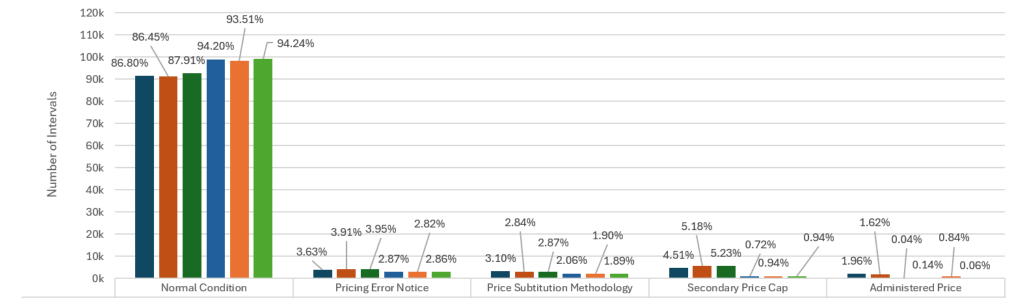
Administered Price was imposed for 148 intervals, or 0.14%, in Luzon; 883 intervals, or 0.84%, in Visayas; and 64 intervals, or 0.06%, in Mindanao. Compared with 2024, Administered Price intervals declined significantly in Luzon, from 2,069 intervals to 148 intervals, and in Visayas, from 1,707 intervals to 883 intervals. Mindanao recorded a slight increase in Administered Price intervals, although the absolute count remained low.

### c. Secondary Price Cap (SPC)[10]

Secondary Price Cap impositions declined substantially across all regions in 2025. Luzon recorded 762 SPC intervals, or 0.72%, compared with 4,758 intervals, or 4.51%, in 2024. Visayas recorded 987 intervals, or 0.94%, compared with 5,459 intervals, or 5.18%, while Mindanao recorded 990 intervals, or 0.94%, compared with 5,512 intervals, or 5.23%. On average, SPC impositions declined by approximately 82.65% across the three regions relative to the previous year.

[10] ERC Resolution No. 7 Series of 2021. Secondary Price Cap (SPC) will be imposed if the Cumulative Price Threshold (CPT) was breached by the computed rolling generator-weighted average price on 72nd hour or the equivalent number of intervals.

The reduction in SPC impositions suggests fewer intervals in which cumulative pricing conditions triggered the application of the cap. However, SPC events in 2025 were still primarily associated with periods of elevated outage levels and transmission constraints, particularly those affecting the Luzon-Visayas and Mindanao-Visayas High Voltage Direct Current (HVDC) interconnections.




| | Normal Condition | Pricing Error Notice | Price Subtitution Methodology | Secondary Price Cap | Administered Price |
|---|---|---|---|---|---|
| Luzon 2024 | 91,492 | 3,823 | 3,266 | 4,758 | 2,069 |
| Visayas 2024 | 91,128 | 4,122 | 2,992 | 5,459 | 1,707 |
| Mindanao 2024 | 92,666 | 4,162 | 3,027 | 5,512 | 41 |
| Luzon 2025 | 99,022 | 3,019 | 2,169 | 762 | 148 |
| Visayas 2025 | 98,295 | 2,961 | 1,994 | 987 | 883 |
| Mindanao 2025 | 99,070 | 3,004 | 1,992 | 990 | 64 |

**Figure 27: Pricing Conditions - 2023 to 2025**

## III. Generator Offer Pattern Behavior

This section utilizes the generators' offer pattern behavior prices, in consideration of their availability for each trading interval averaged in an hourly basis. The analysis compares the hourly distribution of offer prices by resource type during 2025 to identify possible changes in bidding behavior across the year.

Figures 28 to 31 present the average 24-hour offer-price distribution for coal, natural gas, hydro, and oil-based power plants. The results show clear differences in offer behavior across technology types. Coal and natural gas plants remained the lower-priced offer sources among the technologies reviewed, with a substantial share of their available capacity consistently offered at PHP 0/MWh and below throughout the year. This offer pattern is consistent with the operating profile of baseload and mid-merit plants thereby largely being contracted by distribution utilities and suppliers.

Coal plants exhibited the most stable offer-price pattern across the 24-hour profile and between the first and second halves of 2025. Most of their available capacity was consistently offered at PHP 0/MWh and below, with only a limited share offered in higher price bands. This suggests limited intraday variation in coal offer behavior and reinforces the role of coal plants as a relatively stable source of low-priced offers in the market.

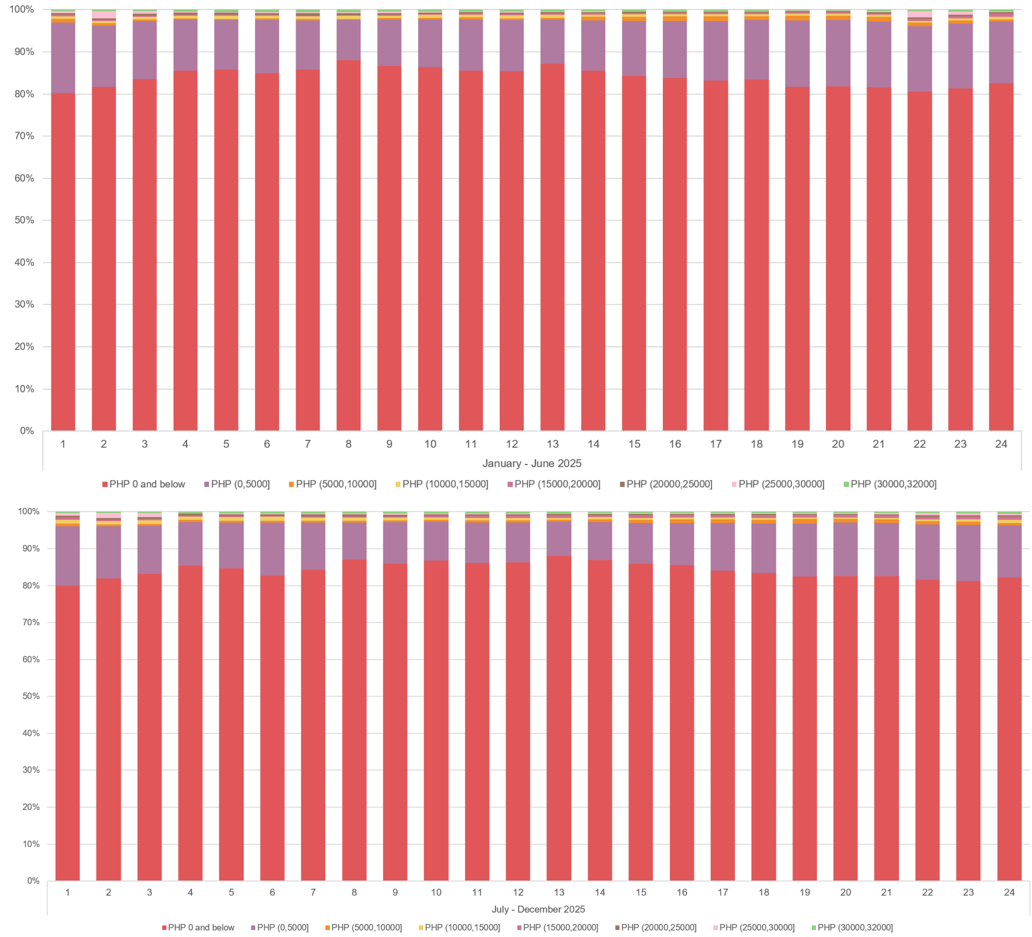



**Figure 28: Coal Offer Pattern - 2025**

Natural gas plants showed a broadly similar pattern, with a substantial portion of available capacity also offered at PHP 0/MWh and below. However, compared with coal, natural gas plants displayed slightly more variation across hours and between the first and second halves of the year. In particular, the second half of 2025 showed a somewhat larger share of natural gas capacity appearing in non-zero or higher offer-price bands during certain hours. This suggests some adjustment in natural gas offer behavior relative to the first half of the year.


**Figure 29: Natural Gas Offer Pattern - 2025**

In contrast, hydro and oil-based plants exhibited more expensive and more variable offer-price profiles. Oil-based plants showed a significant share of available capacity offered in the higher price bands, particularly within the PHP 25,000/MWh to PHP 32,000/MWh ranges. This high-priced offer behavior persisted across the year, although some redistribution across lower and mid-price bands was observed during certain hours in the second half of 2025. The overall offer profile remains consistent with the role of oil-based plants as higher-cost, peaking, or contingency resources that are generally dispatched during tighter system conditions or when lower-priced resources are insufficient.

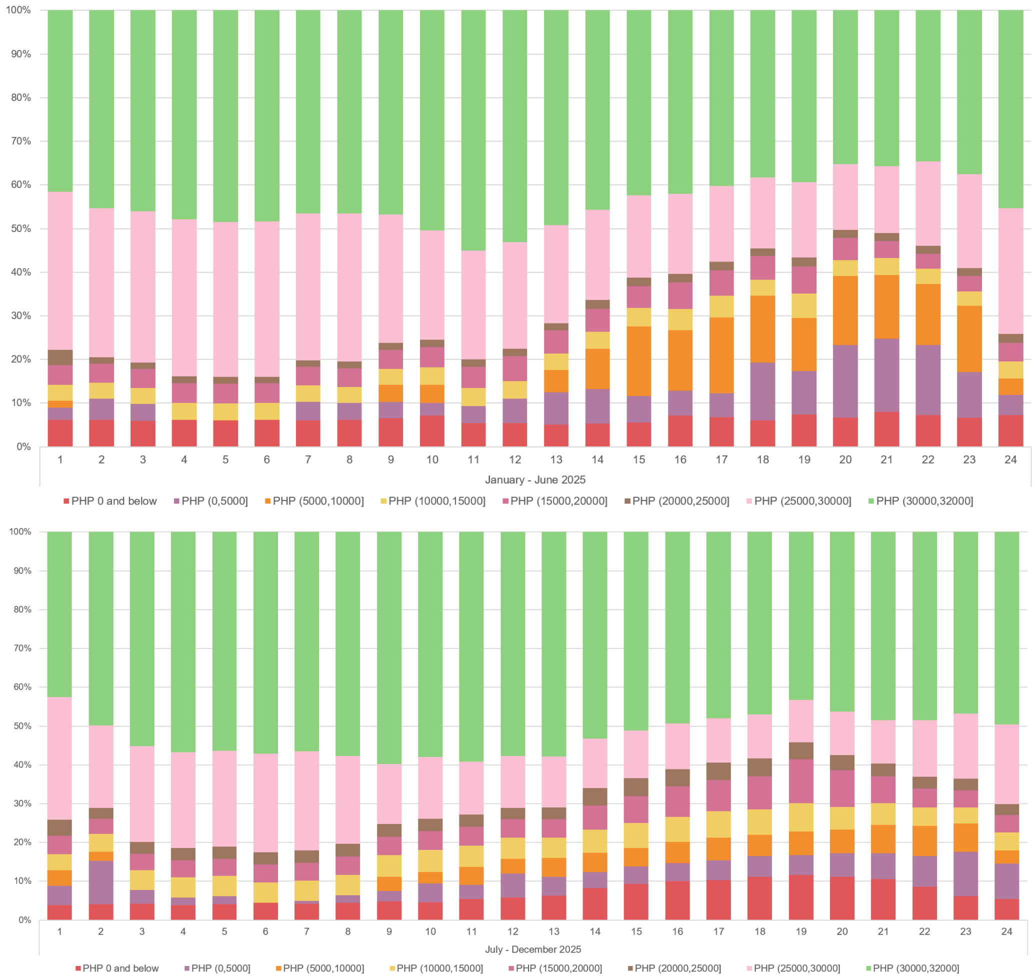



**Figure 30: Oil Offer Pattern – 2025**

Hydro plants showed a more diversified offer-price distribution compared with coal and natural gas. Their available capacity was spread across several price bands, including higher offer-price ranges, indicating more dynamic offer behavior by hour and period. This may reflect the opportunity cost of water, reservoir management considerations, seasonal water availability, and the strategic value of hydro capacity during peak or constrained periods. When considered alongside the observed increase in hydro capacity on outage during the first half of the year, the higher hydro offer-price profile may also indicate tighter availability of hydro resources during certain periods.

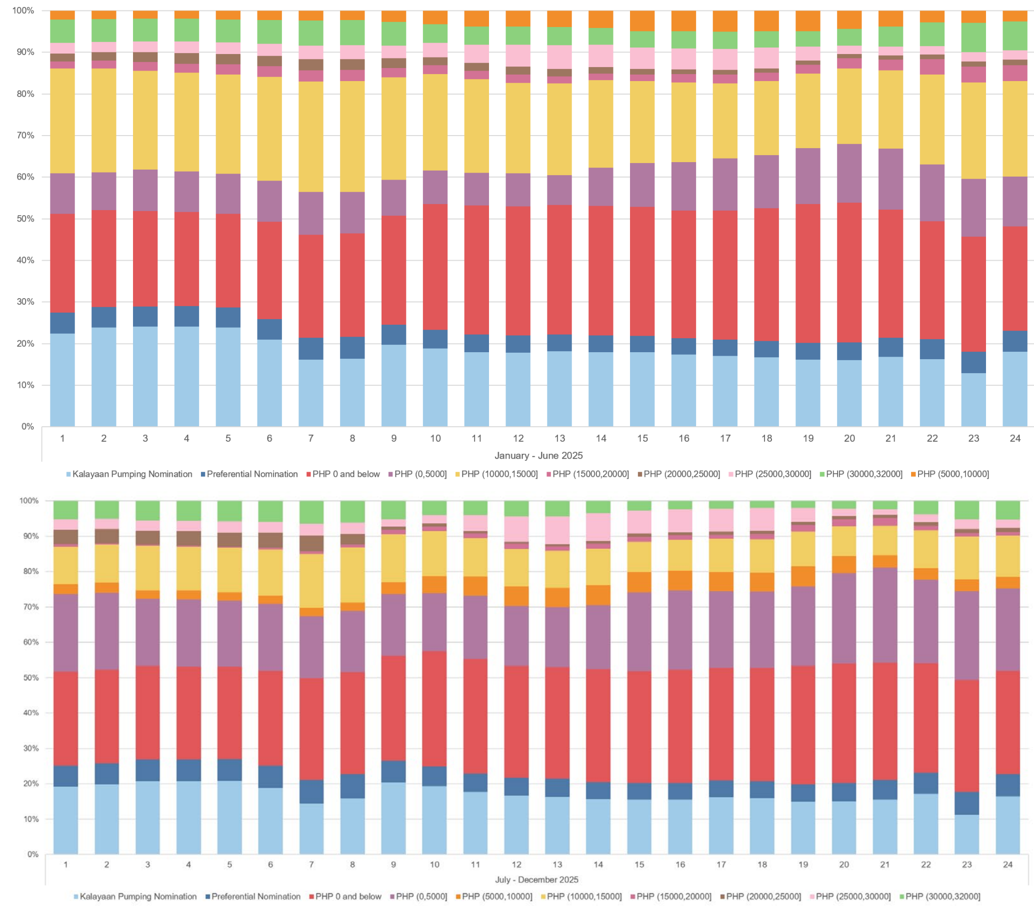



**Figure 31: Hydro Offer Pattern - 2025**

Overall, the charts suggest that the most notable change in bidding behavior was not a broad shift across all technologies, but rather the continued segmentation of offer strategies by plant type. Coal remained stable and predominantly low-priced, natural gas showed moderate variation in its offer-price distribution, while hydro and oil-based plants exhibited more variable and higher-priced offer behavior. However, offer prices should not be interpreted as equivalent to actual dispatch or final market prices.

It is worthy to note that while offer prices were high during this year, the actual dispatch will still be based on the merit ordering of respective offers from the generators with due consideration of the system requirements.

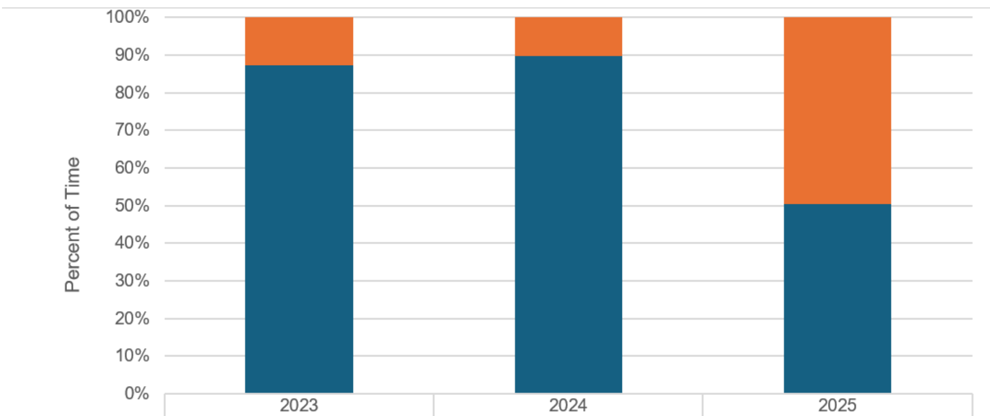
# IV. Competitive Analysis

## A. Residual Supply Index (RSI)[11]

The Residual Supply Index (RSI) provides an indication of market competitiveness by measuring whether available supply, excluding the largest supplier, is sufficient to meet demand. An RSI below 100 indicates a condition where the market may be more reliant on pivotal suppliers, while an RSI above 100 suggests a more competitive supply condition

In 2025, overall prices declined by 14.25%, while the number of intervals with RSI above 100 increased by 379.08% compared with the previous year. This indicates a material increase in the frequency of intervals where supply conditions were less dependent on pivotal suppliers. The distribution of RSI outcomes shows that, unlike in 2023 and 2024 where RSI below 100 accounted for the majority of intervals, 2025 recorded a more balanced distribution between intervals below and above the RSI threshold. This suggests an improvement in market competitiveness and supply adequacy conditions during more intervals of the year

The relationship between RSI and market prices is also reflected in the average LWAP by RSI. For intervals where RSI was below 100, the average market price was PHP5,384.87/MWh, while intervals with RSI above 100 recorded a lower average market price of PHP2,557.14/MWh. This is consistent with market expectations, as tighter supply conditions and higher reliance on pivotal suppliers tend to be associated with higher prices, while more competitive supply conditions tend to correspond with lower prices




| | 2023 | 2024 | 2025 |
|---|---|---|---|
| RSI Above 100 | 13,181 | 10,870 | 52,076 |
| RSI Below 100 | 91,387 | 94,533 | 52,997 |

**Figure 32: Residual Supply Index - 2023 to 2025**

[11] The Residual Supply Index (RSI) is a dynamic continuous index measured as the ratio of the available generation without that generator to the total generation required to supply the demand. The Market RSI is measured as the lowest RSI among all generators in the market. A Market RSI less than 100% indicates the presence of pivotal generator/s or supplier/s

Despite the overall improvement in RSI conditions for 2025, periods of higher reliance on pivotal suppliers were still observed, particularly during the summer months. These periods coincided with tighter supply conditions, elevated demand levels, and the reported unavailability of hydro plants associated with resource constraints. This indicates that while market competitiveness improved on an annual basis, short-term system conditions continued to create intervals where supply adequacy was constrained.

Table 9 presents the maximum and minimum RSI values together with their corresponding LWAP, date, and trading interval. The table also shows the intervals with the maximum and minimum LWAP and their corresponding RSI values. These results highlight that extreme price outcomes do not always correspond directly with the highest or lowest RSI values, indicating that other factors, such as outages, reserve requirements, transmission constraints, and pricing conditions, may also influence interval-level market prices.

**Table 9: Max and Min RSI and Price - 2025**

| | RSI | | Date & Time Interval | Price | | Date & Time Interval |
|---|---|---|---|---|---|---|
| **Max** | 117.54 | 2,426.36 | 11/5/2025 0:25 | 51,759.75 | 95.20 | 3/27/2025 18:25 |
| **Min** | 23.07 | 6,527.27 | 4/10/2025 11:55 | (10,466.61) | 108.67 | 5/12/2025 9:05 |

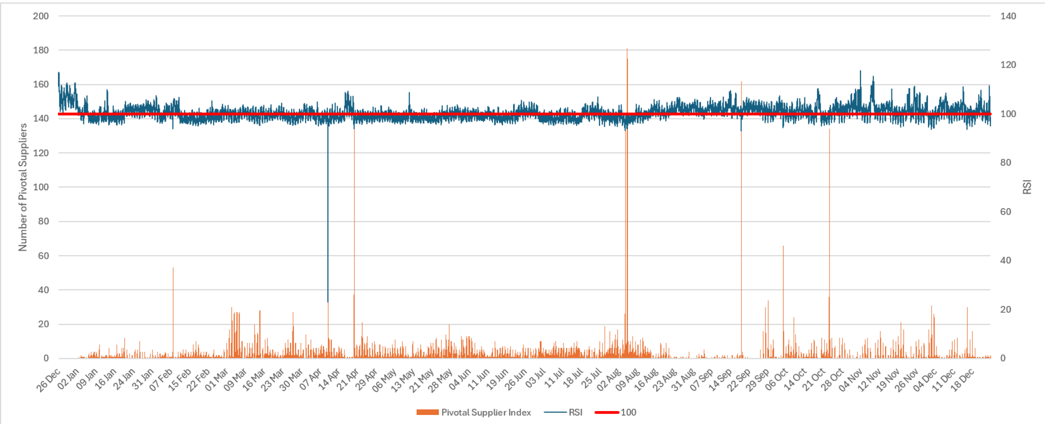



**Figure 33: Per Interval RSI and Pivotal Suppliers - 2025**

## B. Pivotal Suppliers

This section discussed the generating plants whose capacity was critical to meeting system requirements during specific trading intervals. A supplier is considered pivotal when the system becomes more dependent on its available capacity, such that the removal of that supplier may result in insufficient residual supply to meet demand. As such, the frequency of pivotal supplier occurrence provides an indication of the extent to which the market relied on specific large suppliers during the year.

For 2025, GNP Dinginin Coal Power Plant recorded the highest frequency of pivotal supplier occurrence, accounting for 42.78% of trading intervals, equivalent to approximately 44,971 intervals. This was significantly lower than its 2024 level of 81.74%, or around 86,162 intervals. The sharp decline indicates that while GNP Dinginin remained the most frequently pivotal supplier in 2025, the market was less consistently dependent on its capacity compared with the previous year.

A similar year-on-year decline was observed among several major plants. Ilijan NGPP decreased from 51% in 2024 to 15% in 2025, Masinloc CFPP declined from 38% to 11%, Sual CFPP declined from 39% to 9%, Mariveles CFPP declined from 15% to 2%, San Lorenzo NGPP declined from 7% to 1%, and SMC Limay CFPP declined from 12% to 1%. These reductions are consistent with the improvement in RSI conditions discussed in the previous section, where the number of intervals with RSI above 100 increased materially in 2025. This suggests that the market was less frequently reliant on pivotal suppliers during the year.

Notwithstanding the general decline, GNP Dinginin CFPP remained the dominant pivotal supplier, followed by Sta. Rita NGPP at 20%, Ilijan NGPP at 15%, Batangas CCGT at 11%, and Masinloc CFPP at 11%. Batangas CCGT is notable because it appeared as a pivotal supplier in 2025 despite having no recorded pivotal occurrence in 2024.

The composition of the top pivotal suppliers also highlights the system's continued dependence on large thermal generating units. Of the top 12 pivotal suppliers in 2025, seven were coal plants, four were natural gas plants, and one was a hydro plant. This reflects the significance of large-capacity coal and natural gas facilities in maintaining system adequacy, particularly during periods of high demand, outages, or constrained supply conditions.

Overall, the 2025 results show a broad reduction in pivotal supplier occurrence compared with 2024, indicating an improvement in residual supply conditions and market competitiveness. However, the continued presence of several large coal and natural gas plants among the top pivotal suppliers suggests that system reliability and market competitiveness remain sensitive to the availability of major generating units.

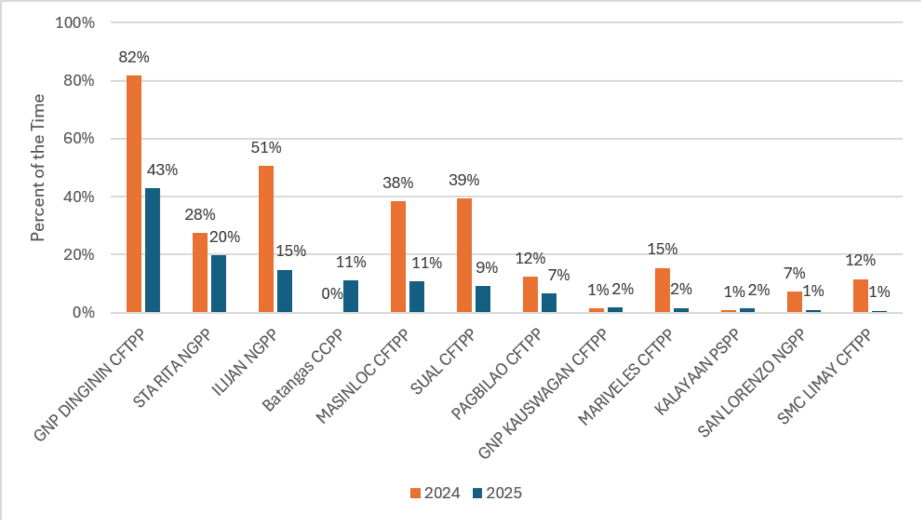



**Figure 34: Top Pivotal Suppliers - 2024 to 2025**

# V. Spot Market Transactions

## A. Spot Exposure

This section presents the trend in spot market exposure and its relationship with LWAP in 2025, compared with the previous year. Spot exposure is measured as the share of load transacted through the spot market, while the remaining requirement is presumed to be covered through bilateral contracts.

On a daily basis, spot energy transactions (in MWh) declined from 22.91% in 2024 to 17.63% in 2025. This indicates a lower reliance on the spot market despite the overall increase in electricity demand. The decline suggests that a larger share of energy requirements may have been covered through bilateral contracts or other contracted arrangements, while spot market transactions accounted for a smaller portion of total load.

Despite the lower level of spot exposure, the market continued to experience interval-level price volatility, as reflected in the movement of LWAP across the year. However, the 2025 LWAP was generally lower than the previous year for many periods, indicating that the reduction in spot exposure coincided with a lower overall price outcome. This should not be interpreted as direct evidence of improved market efficiency, but it suggests that lower exposure to spot market purchases may have helped reduce the impact of volatile spot prices on overall procurement costs.

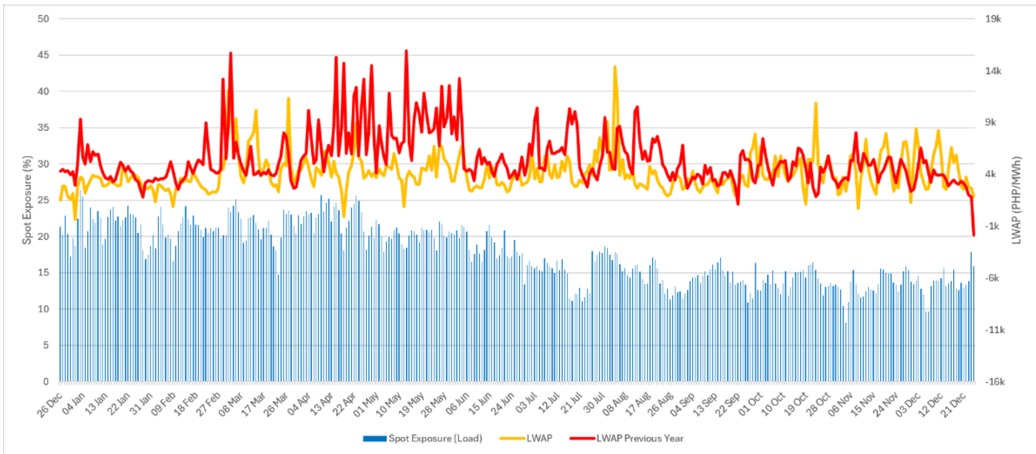



Figure 35: Daily Spot Market Exposure – 2024 vs 2025

On an hourly basis, average spot exposure also declined from 23.10% in 2024 to 17.69% in 2025. The hourly profile shows that spot exposure was lower in 2025 across most, if not all, trading hours compared with the previous year. At the same time, the hourly LWAP profile for 2025 remained below the previous year's level, although both years exhibited a similar intraday price pattern.

The 1200h interval recorded the highest level of spot exposure, while the lowest exposure occurred at around the 1800h interval in both 2024 and 2025. This indicates that the intraday pattern of spot exposure remained broadly similar across the two years, even though the overall level of spot exposure declined in 2025. Overall, the charts suggest that the market relied less on spot transactions in 2025, while price volatility persisted at the daily level and the average hourly LWAP remained lower than in the previous year

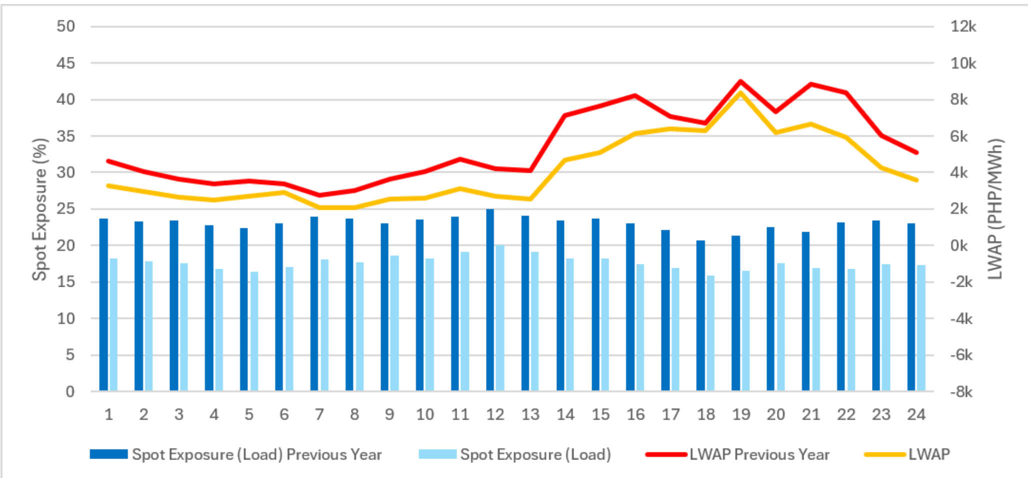



Figure 36: Hourly Spot Market Exposure - 2024 vs 2025

## Annex A-1. Newly Registered Plants - 2025

| Plant Type | Resource ID | Facility Name | Registered Capacity |
|---|---|---|---|
| | | **Luzon** | |
| SOLR | 01AGROSOL_G01 | Agrosolis Solar Power Plant | 3.7 |
| SOLR | 01ARAYSOL_G03 | Arayat 3A Solar Power Project | 30 |
| SOLR | 01BALSOL_G01 | Hermosa Solar Power Project | 24.5 |
| OIL | 01CAPAS_G01 | Capas Bunker C-Fired Diesel Power Plant | 11 |
| SOLR | 01CORDONSOL_G01 | Cordon Solar Power Project | 52.7 |
| SOLR | 01LIMSOL_G01 | Limbauan Solar Power Project (Phase 2) | 28.2 |
| SOLR | 01OLONGSOL_G01 | Olongapo Solar Power Project (SPP) – Phas | 172.2 |
| SOLR | 01SAMLSOL_G01 | Samal Solar Power Project Phase 1 | 35.8 |
| SOLR | 01SNMANSOL_G01 | San Manuel Solar Power Plant | 69.9 |
| BAT | 03BACMAN_BAT | Bac-Man Energy Storage System | 20 |
| SOLR | 03LUMBSOL_G01 | Lumbangan Solar Power Project | 90 |
| SOLR | 03LUNSOL_G01 | Luntal Solar Power Project | 50.1 |
| GEO | 03TANAWON_G01 | Tanawon Geothermal Power Plant | 20.6 |
| | | **Visayas** | |
| SOLR | 04ISIDROSOL_G01 | San Isidro Solar Power Project | 100.5 |
| SOLR | 04TAFTSOL_G01 | Taft Solar Power Plant (SPP) | 17.5 |
| BAT | 04TONGO_BAT | Tongonan Battery Energy Storage System | 14.2 |
| BAT | 06SONEG_BAT | Southern Negros Battery Energy Storage Sys | 10 |
| SOLR | 06VISTASOL_G01 | Vista Alegre Solar Power Project (SPP) | 50.1 |
| OIL | 07BIDPP_G01 | Bohol In-Island Diesel Power Plant | 54 |

## Annex A-2. Plants with Changes in Capacity – 2025

| Plant Type | Resource ID | Facility Name | Registered Capacity 2024 | Registered Capacity 2025 | Year-on-Year Change (MW) |
|---|---|---|---|---|---|
| | | **Luzon** | | | |
| HYD | 01AMPHAW_G01 | Ampohaw Hydroelectric Power Plant | 12.5 | 8.3 | -4.2 |
| HYD | 01ANGAT_A | Angat Hydroelectric Power Plant Unit A | 38.7 | 44.6 | 5.9 |
| HYD | 01ANGAT_M | Angat Hydroelectric Power Plant (Angat HEPP) Unit M | 200 | 149.5 | -50.5 |
| WIND | 01BALWIND_G01 | Balaoi and Caunayan Wind Power Project Phase 1 | 80 | 22.4 | -57.6 |
| SOLR | 01BONGSOL_G01 | Bongabon Solar Power Project | 18.8 | 19.8 | 1 |
| WIND | 01CAPRIS_G02 | Caparispisan II Wind Power Project | 50 | 45.1 | -4.9 |
| SOLR | 01CONSOL_G01 | Concepcion 1 Solar Power Project | 76 | 82.5 | 6.5 |
| SOLR | 01MEGASOL_G01 | Gamu Solar Power Project | 46.2 | 41.2 | -5 |
| COAL | 01MPGC_U01 | Mariveles Coal-Fired Power Plant (CFPP) Unit 1 | 150 | 135 | -15 |
| COAL | 01MPGC_U02 | Mariveles Coal-Fired Power Plant (CFPP) Unit 2 | 150 | 133 | -17 |
| COAL | 01MPGC_U03 | Mariveles Coal-Fired Power Plant (CFPP) Unit 3 | 150 | 133 | -17 |
| COAL | 01MPGC_U04 | Mariveles Coal-Fired Power Plant (CFPP) Unit 4 | 150 | 137 | -13 |
| BAT | 01MSINLO_BAT | Masinloc Battery Energy Storage System | 10 | 30 | 20 |
| COAL | 01MSINLO_G01 | Masinloc Coal-Fired Thermal Power Plant Unit 1 | 344 | 322.7 | -21.3 |
| COAL | 01MSINLO_G02 | Masinloc Coal-Fired Thermal Power Plant Unit 2 | 344 | 322.7 | -21.3 |
| COAL | 01MSINLO_G03 | Masinloc Coal-Fired Thermal Power Plant Unit 3 | 335 | 307.2 | -27.8 |
| COAL | 01PETRON_G01 | Refinery Solid Fuel-Fired Boiler Power Plant (RSFFBPP) | 140 | 141.4 | 1.4 |
| COAL | 01SMC_G01 | SMC Limay Coal Power Plant 1 | 150 | 134 | -16 |
| COAL | 01SMC_G02 | SMC Limay Coal Power Plant 2 | 150 | 134 | -16 |
| COAL | 01SMC_G03 | SMC Limay Coal Power Plant 3 | 150 | 134 | -16 |
| COAL | 01SMC_G04 | SMC Limay Coal Power Plant 4 | 150 | 134 | -16 |
| COAL | 01SUAL_G01 | Sual Coal-Fired Power Thermal Plant 1 | 647 | 600 | -47 |
| COAL | 01SUAL_G02 | Sual Coal-Fired Power Thermal Plant 2 | 647 | 600 | -47 |
| SOLR | 01SUPSOL_G01 | Subic New PV Power Plant Project | 62.7 | 61.6 | -1.1 |
| OIL | 01TPCBUNK_G01 | Bunker C-Fired Diesel Power Plant | 17.9 | 16.8 | -1.1 |
| COAL | 03CALACA_G01 | Pulverized Coal Fired Power Plant Unit 1 | 240 | 239.9 | -0.1 |
| COAL | 03CALACA_G02 | Pulverized Coal Fired Power Plant Unit 2 | 300 | 290 | -10 |
| HYD | 03CALIRY_G01 | Caliraya Hydroelectric Power Plant (CHEPP) | 28 | 37 | 9 |
| NATG | 03EERI_G01 | Batangas Combined Cycle Power Plant Unit 1 | 440 | 420.6 | -19.4 |
| NATG | 03EERI_G02 | Batangas Combined Cycle Power Plant Unit 2 | 440 | 421.9 | -18.1 |
| NATG | 03EERI_G03 | Batangas Combined Cycle Power Plant Unit 3 | 440 | 419.6 | -20.4 |
| GEO | 03ORMAT_G01 | Makban-Binary 1 Geothermal Power Plant | 6 | 3 | -3 |
| GEO | 03PALAYAN_G01 | Palayan Binary Power Plant | 31 | 24 | -7 |
| COAL | 03SLTEC_G02 | South Luzon Thermal Energy Corporation Coal-Fired Thermal Power Plant Unit 2 | 124 | 123 | -1 |
| GEO | 03TGPP_G01 | Tiwi Geothermal Binary Power Plant | 16.7 | 9.7 | -7 |
| | | **Visayas** | | | |
| OIL | 04CLBYBNK_G01 | Calbayog Bunker C-Fired Diesel Power Plant | 11 | 10.9 | -0.1 |
| OIL | 04IASMOD_G02 | Isabel Modular Diesel Power Plant Sector 2 | 10.1 | 10 | -0.1 |
| OIL | 04IASMOD_G03 | Isabel Modular Diesel Power Plant Sector 3 | 15.1 | 15 | -0.1 |
| OIL | 04IASMOD_G04 | Isabel Modular Diesel Power Plant Sector 4 | 10.2 | 10 | -0.2 |
| OIL | 04IASMOD_G05 | Isabel Modular Diesel Power Plant Sector 5 | 15.1 | 15 | -0.1 |
| OIL | 04IASMOD_G06 | Isabel Modular Diesel Power Plant Sector 6 | 10.2 | 10 | -0.2 |
| HYD | 04UTH_G01 | Upper Taft Hydroelectric Power Plant | 14.2 | 13.8 | -0.4 |
| OIL | 05CPPC_U08 | Bunker C-Fired Diesel Power Plant (BCFDPP) Unit 8 | 6.5 | 6.3 | -0.2 |
| OIL | 05CPPC_U09 | Bunker C-Fired Diesel Power Plant (BCFDPP) Unit 9 | 6.5 | 6.3 | -0.2 |
| OIL | 05CPPC_U10 | Bunker C-Fired Diesel Power Plant (BCFDPP) Unit 10 | 6.5 | 6.3 | -0.2 |
| SOLR | 05TOLSOL_G01 | Toledo Solar Power Plant | 49 | 48 | -1 |
| BIOF | 06BISCOM_G01 | Biomass Cogeneration Power Plan | 30 | 12.7 | -17.3 |
| OIL | 06CENPRI_U01 | Unit 1 Calumangan Bunker C-Fired Diesel Power Plant | 4.5 | 4.4 | -0.1 |
| OIL | 06CENPRI_U02 | Unit 2 Calumangan Bunker C-Fired Diesel Power Plant | 4.5 | 4.4 | -0.1 |
| OIL | 06CENPRI_U03 | Unit 3 Calumangan Bunker C-Fired Diesel Power Plant | 4.5 | 4.4 | -0.1 |
| OIL | 06CENPRI_U04 | Unit 4 Calumangan Bunker C-Fired Diesel Power Plant | 6.7 | 6.5 | -0.2 |
| OIL | 06CENPRI_U05 | Unit 5 Calumangan Bunker C-Fired Diesel Power Plant | 6.7 | 6.5 | -0.2 |
| GEO | 06PAL2A_U01 | Palinpinon-2 Geothermal Power Plant (PGPP2) Unit 1 | 20 | 18.8 | -1.2 |
| GEO | 06PAL2A_U02 | Palinpinon-2 Geothermal Power Plant (PGPP2) Unit 2 | 20 | 18.9 | -1.1 |
| GEO | 06PAL2A_U03 | Palinpinon-2 Geothermal Power Plant (PGPP2) Unit 3 | 20 | 18.9 | -1.1 |
| BIOF | 06STNEGB_G01 | SNBP Biomass Power Plant (BPP) | 25 | 21.9 | -3.1 |
| BIOF | 06URC_G01 | Kabankalan Biomass Power Plant (BPP) | 20 | 19.7 | -0.3 |
| WIND | 08SLWIND_G01 | San Lorenzo Wind Power Plant | 54 | 52.9 | -1.1 |
| HYD | 08TIMBA_G01 | Timbaban Hydroelectric Power Plant | 18 | 17.8 | -0.2 |

| Plant Type | Resource ID | Facility Name | Registered Capacity | | Year-on-Year Change (MW) |
|---|---|---|---|---|---|
| | | | 2024 | 2025 | |
| **Mindanao** | | | | | |
| OIL | 09PANABNK_U01 | Misamis Occidental BCFDPP 2 Unit 1 | 7.8 | 7.5 | -0.3 |
| OIL | 09PANABNK_U02 | Misamis Occidental BCFDPP 2 Unit 2 | 7.8 | 7.5 | -0.3 |
| HYD | 10LIAN_G01 | Liangan Hydroelectric Power Project | 11.9 | 11.6 | -0.3 |
| COAL | 10PPEI_U01 | Coal-Fired Thermal Power Plant | 20 | 24.1 | 4.1 |
| BIOF | 11CRYSSUG_G01 | Biomass Cogeneration Plant | 12 | 8 | -4 |
| COAL | 11MINBAL_G01 | Balingasag Coal Fired Thermal Power Plant Units 1-3 | 165 | 150 | -15 |
| HYD | 11MINBU_G01 | Bubunawan Hydroelectric Power Plant | 6.6 | 6.2 | -0.4 |
| OIL | 11MNRGY_G02 | Diesel Power Plant (Wartzila) | 26 | 25 | -1 |
| COAL | 11STEAG_U01 | Mindanao Coal Fired Thermal Power Plant 1 | 116 | 105 | -11 |
| COAL | 11STEAG_U02 | Mindanao Coal Fired Thermal Power Plant 2 | 116 | 105 | -11 |
| OIL | 12NACSUR_G01 | 10.944 MW Diesel Power Plant | 10.7 | 10.4 | -0.3 |
| OIL | 13MATIBNK_G01 | Mati Bunker C-Fired Diesel Power Plant | 11 | 10.9 | -0.1 |
| COAL | 13SMC_U01 | Malita Circulating Fluidized Bed Coal Fired Thermal Power Plant (CFBCFTPP) Unit 1 | 149.9 | 133.1 | -16.8 |
| COAL | 13SMC_U02 | Malita Circulating Fluidized Bed Coal Fired Thermal Power Plant (CFBCFTPP) Unit 2 | 150 | 135.7 | -14.3 |
| GEO | 14MTAPO_U02 | Mindanao II Geothermal Power Plant | 50 | 50.6 | 0.6 |
| OIL | 14SUPKOR_G01 | Koronadal Bunker C-Fired Diesel Power Plant | 11.9 | 11.5 | -0.4 |

## Annex A-3. Mothballed, Deregistered, Disaggregated, and Ceased Plants - 2025

| Plant Type | Resource ID | Registered Capacity | Remarks |
|---|---|---|---|
| **Luzon** | | | |
| HYD | 01CASECN_G01 | 168 | Disaggregated |
| OIL | 02TMOBIL_G02 | 41.2 | Mothballed |
| OIL | 02TMOBIL_G04 | 44 | Mothballed |
| GEO | 03MKBN_C | 30 | Mothballed |
| **Visayas** | | | |
| OIL | 05EAUC_U01 | 11.5 | Deregistered |
| OIL | 05TPVI_U01 | 5.5 | Ceased |
| OIL | 05TPVI_U02 | 5.5 | Ceased |
| OIL | 05TPVI_U03 | 5.5 | Ceased |
| OIL | 05TPVI_U04 | 5.5 | Ceased |
| OIL | 05TPVI_U05 | 5.5 | Ceased |
| OIL | 05TPVI_U06 | 5.5 | Ceased |
| GEO | 06PAL1A_G01 | 112.4 | Disaggregated |
| **Mindanao** | | | |
| OIL | 10IDPP_G01 | 102 | Disaggregated |

## Annex B. Yellow Alert Occurrences - 2025

| Date | Time Interval | Time Lifted | Remarks |
|---|---|---|---|
| **Luzon** | | | |
| 05 March 2025 | 1800h - 1900h | 1949h | Yellow Alert was declared due to high demand forecast and insufficient Operating Margin<br><br>Outage - 1,639.3 MW<br>Deration - 1,723.3 MW |
| **Visayas** | | | |
| 01 August 2025 | 1900h - 2000h | 2035h | Yellow Alert was declared due to successive unplanned outages of generating units in Mindanao combined with existing outages in Visayas<br><br>Outage - 204.1 MW<br>Deration - 218.9 MW |
| 04 August 2025 | 1900h | 1938h | Yellow Alert was declared due to successive unplanned outages of generating units in Mindanao combined with existing outages in Visayas<br><br>Outage - 221.1 MW<br>Deration - 369.9 MW |
| 05 August 2025 | 1400h - 2100h | 2104h | Yellow Alert was declared due to successive unplanned outages of generating units in Mindanao combined with existing outages in Visayas<br><br>Outage - 390.1 MW<br>Deration - 353.9 MW |
| 06 August 2025 | 1600h, 1800h, and 1900h | 1300h | Yellow Alert was declared due to successive unplanned outages of generating units in Mindanao combined with existing outages in Visayas<br><br>Outage - 385.1 MW<br>Deration - 340.1 MW |
| 01 October 2025 | 1400h - 2100h | 2100h | Yellow Alert was declared due to a magnitude 6.9 earthquake that struck the Visayas Region<br><br>Outage - 385.1 MW<br>Deration - 340.1 MW |
| 19 November 2025 | 1600h - 2000h | 2025h | Yellow Alert was declared due to successive unplanned outages of generating units in Visayas<br><br>Outage - 557.1 MW<br>Deration - 341.5 MW |
| 20 November 2025 | 1800h - 1900h | 1300h | Yellow Alert was declared due to successive unplanned outages of generating units in Visayas<br><br>Outage - 368.8 MW<br>Deration - 291.7 MW |
| 11 December 2025 | 1800h | 1300h | Yellow Alert was declared due to successive unplanned outages of generating units in Mindanao combined with existing outages in Visayas<br><br>Outage - 226.9 MW<br>Deration - 255.51 MW |
| **Mindanao** | | | |
| 01 August 2025 | 1900h - 2000h | 1946h | Yellow Alert was declared due to significant successive unplanned outages<br><br>Outage - 579 MW<br>Deration - 59.3 MW |

# Annex C. Market Intervention and Suspension List

| Start Interval | End Interval | No. of Intervals | Initiated by | Region | Reason |
|---|---|---|---|---|---|
| 08-Feb-2025 17:40 | 08-Feb-2025 18:45 | 14 | SO | V | Unavailability of real-time data from the Visayas System Operator due to the down state of the Visayas ICCP data source |
| 10-Apr-2025 11:55 | 10-Apr-2025 12:30 | 8 | MO | LVM | Network connection problem that caused market applications to be disconnected from the main netwrok backbone, preventing transmission and publication of scheduling and pricing results |
| 11-Jun-2025 23:10 | 12-Jun-2025 00:00 | 11 | MO | LVM | Failure to initiate oprimization and generate a RTD schedule resulting from software failure to pre-process the input data to the MMS. |
| 14-Jun-2025 23:10 | 15-Jun-2025 00:00 | 11 | MO | LVM | Failure to initiate oprimization and generate a RTD schedule resulting from software failure to pre-process the input data to the MMS. |
| 16-Sep-2025 07:25 | 16-Sep-2025 08:00 | 8 | MO | LVM | Failure of the MMS to generate RTD results following the switchover of the Market Management System (MMS) from the main site to the backup site. |
| 16-Sep-2025 09:20 | 16-Sep-2025 09:20 | 1 | MO | LVM | Failure of the MMS to generate RTD results following the switchover of the Market Management System (MMS) from the main site to the backup site. |
| 16-Sep-2025 09:35 | 16-Sep-2025 09:35 | 1 | MO | LVM | Failure of the MMS to generate RTD results following the switchover of the Market Management System (MMS) from the main site to the backup site. |
| 19-Sep-2025 07:20 | 19-Sep-2025 07:35 | 4 | MO | LVM | Failure of the MMS to generate RTD results following the system switchover downtime from the main site to the backup site. |
| 19-Sep-2025 11:15 | 19-Sep-2025 11:25 | 3 | MO | LVM | Failure of the MMS to generate RTD results following the system switchover downtime from the main site to the backup site. |
| 30-Sep-2025 22:05 | 01-Oct-2025 19:15 | 255 | SO | V | Multiple tripping of transmission lines and generators due to 6.9 magnitude earthquake in Cebu |
| 01-Oct-2025 03:00 | 01-Oct-2025 03:10 | 3 | MO | LVM* | Failure to generate RTD results due to partial outage of SO communication links (Cebu earthquake) |
| 01-Oct-2025 01:45 | 02-Oct-2025 04:00 | 316 | ERC | Bohol Sub-Grid | Multiple line trippings and widespread power outages caused by Cebu Earthquake |
| 01-Oct-2025 01:45 | 02-Oct-2025 19:10 | 498 | ERC | Leyte Sub-Grid | Multiple line trippings and widespread power outages caused by Cebu Earthquake |

| Start Interval | End Interval | No. of Intervals | Initiated by | Region | Reason |
|---|---|---|---|---|---|
| 09-Oct-2025 17:05 | 09-Oct-2025 17:05 | 1 | MO | LVM | Failure to generate RTD results due to incomplete transfer of input data from COP (process timeout) |
| 09-Oct-2025 17:55 | 09-Oct-2025 18:00 | 2 | MO | LVM | Failure to generate RTD results due to incomplete transfer of input data from COP (process timeout) |
| 10-Oct-2025 09:45 | 10-Oct-2025 10:15 | 7 | MO | M | Multiple tripping of transmission lines and generators due to 7.6 magnitude earthquake in the Davao Oriental area |
| 10-Oct-2025 14:50 | 10-Oct-2025 15:50 | 13 | SO | V | MLD implementation to prevent overloading of Cebu-Mandaue 138kV Line 2 |
| 15-Oct-2025 10:15 | 15-Oct-2025 11:15 | 13 | SO | V | MLD implementation to prevent overloading of Compostela SS 100MVA TR2 |
| 15-Oct-2025 13:30 | 15-Oct-2025 17:00 | 43 | SO | V | MLD implementation to prevent overloading of Cebu-Mandaue 138kV L2 |
| 24-Oct-2025 09:30 | 24-Oct-2025 11:55 | 30 | SO | V | MLD implementation to prevent overloading of Cebu-Mandaue 138kV L2 |
| 04-Nov-2025 08:00 | 05-Nov-2025 17:55 | 408 | ERC | V | Multiple line trippings and widespread power outages caused by Typhoon Tino |
| 04-Nov-2025 10:35 | 04-Nov-2025 20:45 | 123 | SO | V | Unimplementable RTD due to extreme low demand during Typhoon Tino |
| 04-Nov-2025 11:05 | 04-Nov-2025 11:10 | 2 | MO | LVM* | Failure to publish RTD results due to optimization timeout owing to abnormal system conditions (Typhoon Tino) |
| 05-Nov-2025 00:20 | 05-Nov-2025 00:20 | 1 | MO | LVM* | Failure to publish RTD results due to optimization timeout owing to abnormal system conditions (Typhoon Tino) |
| 10-Nov-2025 01:30 | 10-Nov-2025 09:00 | 91 | SO | L | Multiple line Tripping and Equipment Outages caused by Super Typhoon Uwan |
| 11-Nov-2025 13:35 | 11-Nov-2025 16:10 | 32 | SO | V | MLD implementation to prevent overloading of Cebu-Mandaue 138kV L2 |
| 12-Nov-2025 13:40 | 12-Nov-2025 15:35 | 24 | SO | V | MLD implementation to prevent overloading of Cebu-Mandaue 138kV L2 |
| 13-Dec-2025 13:25 | 13-Dec-2025 13:25 | 1 | MO | LVM | Failure to publish RTD results due to timeout condition caused by simultaneous constraints |

## Annex D. Year-on-Year Statistics

| | 2024<br>26 Dec 2023 to 25 Dec 2024 | 2025<br>26 Dec 2024 to 25 Dec 2025 | Year-on-Year Statistics |
|---|---|---|---|
| | **Average** | **Average** | |
| Capacity Offered / Nominated (MW) | 18,897.85 | 20,434.46 | 8.13% |
| Capacity on Commissioning (MW) | 1,463.45 | 602.98 | -58.80% |
| Capacity Not Offered / Nominated (MW) | 4,552.32 | 5,275.23 | 15.88% |
| Capacity on Outage (MW) | 3,671.81 | 3,513.92 | -4.30% |
| Effective Supply (MW) | 16,368.63 | 17,968.72 | 9.78% |
| Demand (MW) | 13,903.74 | 13,962.83 | 0.43% |
| LWAP (PHP/MWh) | 5,583.01 | 3,981.72 | -28.68% |
| **Outage Per Plant Type (MW)** | | | |
| Coal | 1,580.00 | 1,727.10 | 9.31% |
| Natural Gas | 847.00 | 674.57 | -20.36% |
| Oil | 481.00 | 543.65 | 13.03% |
| Hydro | 616.00 | 383.77 | -37.70% |
| Geothermal | 196.00 | 203.23 | 3.69% |
| Biofuel | 96.00 | 60.72 | -36.75% |
| Battery | 43.00 | 59.97 | 39.48% |
| Wind | 82.00 | 57.28 | -30.15% |
| Solar | 37.00 | 37.39 | 1.06% |
| **Outage Per Category (MW)** | | | |
| Forced | 1,974.94 | 1,841.98 | -6.73% |
| Planned | 1,257.17 | 1,338.14 | 6.44% |
| Maintenance | 536.53 | 356.66 | -33.53% |
| Deactivated Shutdown | | 18.33 | |