



**4Q**  
**25**

**Earnings  
Release**

MARCH  
2026

## CONTENTS

<b>The Quarter at a Glance</b> .....	<b>4</b>
<b>Message from Management</b> .....	<b>6</b>
<b>Energy Market</b> .....	<b>8</b>
<b>Performance by Business Unit</b> .....	<b>14</b>
Generation .....	14
Auren's Noncontrolling Interests.....	27
Commercialization .....	29
<b>Consolidated Financial Performance</b> .....	<b>31</b>
<b>Other Material Information</b> .....	<b>40</b>

## Earnings Call

**March 04, 2026**

(In Portuguese with simultaneous translation into English)

**10:00 am** (Brasília) | **08:00 am** (New York) | **1:00 pm** (London)

[Click here](#) to view the webcast.

Earnings Presentation available at: [ri.aurenenergia.com.br](https://ri.aurenenergia.com.br)

## Contact Information

### Investor Relations

- **Mateus Ferreira** (Financial and Investor Relations Vice President)
- **Marcelo Sá** (Investor Relations Officer)
- **Juliana Ramirez** (Investor Relations Manager)
- **Emille Reckia** (Investor Relations Consultant)
- **Bruna Freixo** (Investor Relations Analyst)
- **Bruno Tavares** (Investor Relations Analyst)

[ri@arenenergia.com.br](mailto:ri@arenenergia.com.br)

[ri.aurenenergia.com.br](https://ri.aurenenergia.com.br)

As of December 31, 2025:

**AURE3:**  
R\$ 11.87

**Market Cap:**  
R\$ 12.5 billion

## The Quarter at a Glance

Auren reports **Adjusted EBITDA of R\$ 1.0 billion** in 4Q25, achieving a **record Adjusted EBITDA of R\$ 4.0 billion in 2025, up 20%** compared to 2024 pro forma

**Synergy Captures:** Auren continued to capture recurring synergies in PMSO expenses, generating savings of R\$ 66.0 million in 4Q25 and totaling **R\$ 278.7 million since the acquisition of AES Brasil**, completed on October 31, 2024. This amount exceeds the previously indicated annual level of R\$ 250 million, and more than doubled the amount initially announced at the time of the transaction of R\$ 120 million.

**Wind Asset Availability:** in December, we recorded **average availability of 94.6% across the incorporated wind assets**, surpassing the 95% level in the final two weeks of the month. This was achieved one year ahead of the timeline established during the due diligence process. Wind assets generated 1.2 GWavg<sup>1</sup>, 4.9% less than the same period in 2024, equivalent to 86.0% of the certified P90 generation. **Potential generation exceeded the P50 certification both in the quarter and in the year, reinforcing the quality of the assets and the accuracy of the updated certifications.** In 4Q25, potential generation<sup>2</sup> – excluding curtailment – reached 111.5% of P90 and 101.6% of P50. In 2025, potential generation reached 109.7% of P90 and 100.2% of P50.

**Adjusted EBITDA and Leverage:** Auren reported an **adjusted EBITDA of R\$ 1.0 billion in 4Q25**, an increase of 13.5% on the same period last year. In 2025, **Adjusted EBITDA totaled R\$ 4.0 billion**, up 19.9% compared to proforma 2024 (R\$ 3.3 billion). Leverage at the end of the quarter stood at **4.8x Net Debt/LTM Adjusted EBITDA**. During the quarter, we recognized **indemnification for CESP's prudent investments** in the amount of R\$ 498.8 million, based on the reference date corresponding to the end of the concession agreements, **with a positive impact of R\$ 142.8 million on Adjusted EBITDA**.

**Benefits of a Diversified Portfolio:** in 4Q25, the Company secured modulation gains of R\$ 70.4 million, stemming from the Company's hourly generation profile and prevailing market price dynamics, **helping to offset a significant portion of the curtailment impact**. After accounting for modulation gains, the net curtailment impact in the quarter was R\$ 137.0 million. Over 2025, **the Company recorded gains of R\$ 195.9 million from modulation and a net negative curtailment impact of R\$ 333.6 million**.

**Pension Liability Immunization:** Previc approved the actuarial rate of 6.28% for the CESP plan, confirming a reduction of **R\$ 879 million** in the actuarial deficit and preventing an increase of approximately **R\$ 47 million** in annual contributions starting in 2026. Following the same approach adopted at CESP, the immunization strategy was also implemented for the Auren Operações plan, aligning asset returns and maturities with future liabilities. Among other benefits, this strategy reduces the Company's actuarial deficit by **R\$ 112 million** and avoids an increase of **R\$ 7 million** in annual contributions **from 2026**.

**Law 15.269/2025 and Public Consultation No. 210:** Law No. 15.269/2025 was enacted on November 24, 2025. The approved legislation allows **reimbursement for generation cuts (curtailment) related to operational reliability risks** in the National Interconnected Grid. To regulate these provisions, the Ministry of Mines and Energy (MME) launched Public Consultation No. 210 on December 31, 2025. Following the conclusion of the public contribution period, we are awaiting the publication of the final regulation by the MME.

<sup>1</sup> Includes actual generation plus the energy to be compensated due to curtailment classified as External Unavailability ("REL"), after reaching the allowance.

<sup>2</sup> Potential generation = energy produced + portion of energy not produced due to various types of restrictions imposed by the National System Operator (ONS).

## | Table 1 | Period Overview – Operational and Financial Information

### Operational Headlines

Generation (MWavg)	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
Hydro	1,812.6	2,033.1	-10.8%	1,937.7	1,831.0	5.8%
Wind <sup>1</sup>	1,178.2	1,238.6	-4.9%	1,242.0	1,139.6	9.0%
Solar <sup>1</sup>	178.2	189.4	-5.9%	172.8	141.0	22.5%
<b>Total Proprietary Assets</b>	<b>3,169.0</b>	<b>3,461.1</b>	<b>-8.4%</b>	<b>3,352.5</b>	<b>3,111.6</b>	<b>7.7%</b>
Interests <sup>2</sup>	305.0	307.7	-0.9%	259.4	356.0	-27.1%
<b>Total Proprietary Assets and Holdings</b>	<b>3,474.0</b>	<b>3,768.7</b>	<b>-7.8%</b>	<b>3,611.9</b>	<b>3,467.6</b>	<b>4.2%</b>

Average Availability Wind Assets	4Q25	4Q24 proforma	Change (p.p.)	2025	2024 proforma	Change (p.p.)
Consolidated Portfolio	94.2%	92.5%	<b>1.7</b>	93.6%	87.9%	<b>5.7</b>
Acquired Assets	93.0%	90.6%	<b>2.4</b>	92.1%	84.0%	<b>8.1</b>

### Summary Financials

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
<b>Net Revenue</b>	<b>3,801.7</b>	<b>3,598.9</b>	<b>5.6%</b>	<b>13,177.0</b>	<b>11,250.8</b>	<b>17.1%</b>
Generation	1,702.3	1,795.5	-5.2%	6,556.1	6,088.6	7.7%
Sales	2,916.1	2,602.9	12.0%	9,244.4	7,079.8	30.6%
Eliminations	(816.7)	(799.5)	2.2%	(2,623.6)	(1,917.6)	36.8%
<b>Adjusted EBITDA<sup>3</sup></b>	<b>1,009.7</b>	<b>889.8</b>	<b>13.5%</b>	<b>3,968.3</b>	<b>3,309.9</b>	<b>19.9%</b>
Generation	1,075.4	954.1	12.7%	3,940.8	3,238.3	21.7%
Sales	(22.8)	(31.3)	-27.1%	170.9	202.1	-15.4%
Holding Company and Pipeline	(42.9)	(33.0)	30.0%	(143.5)	(130.6)	9.8%
Adjusted EBITDA Margin	26.6%	24.7%	1.8 p.p.	30.1%	29.4%	0.7 p.p.
<b>Net Profit</b>	<b>354.7</b>	<b>(363.6)</b>	<b>n.a.</b>	<b>(557.9)</b>	<b>(32.7)</b>	<b>n.a.</b>
<b>Operating Cash Flow after Debt Service</b>	<b>154.3</b>	<b>508.5</b>	<b>-69.7%</b>	<b>1,321.5</b>	<b>1,658.9</b>	<b>-20.3%</b>
Cash Conversion Ratio	15.3%	57.1%	-41.9 p.p.	33.3%	50.1%	-16.8 p.p.
Net Debt	19,237.0	18,919.2	1.7%	19,237.0	18,919.2	1.7%
<b>Leverage</b>	<b>4.8x</b>	<b>5.7x</b>	<b>-0.9x</b>	<b>4.8x</b>	<b>5.7x</b>	<b>-0.9x</b>

**Note:** The Financial Performance section of this release presents an analysis of the Company's main earnings components. Given the completion of the acquisition of AES Brasil Energia S.A. on October 31, 2024, and in order to assist the market in analyzing the results and to facilitate the visualization and interpretation of the Company's 4Q25 data, the figures related to the 2024 Financial Statements are presented on an unaudited pro forma basis, and embrace the combined operations of AES Brasil Energia S.A. and the Company from 01/01/2024, solely to facilitate a comparative analysis. The accounting results of Auren Energia S.A. and AES Brasil Energia S.A., as disclosed in the 2024 Quarterly Financial Statements, were accordingly consolidated by summing the figures of both companies and eliminating intercompany transactions. Additionally, reclassifications were made to items in the statement of profit or loss (DRE) to facilitate a comparative analysis and improve presentation.

<sup>1</sup> Includes actual generation plus the energy to be compensated due to curtailment classified as External Unavailability (REL), after reaching the allowance. For wind energy, this includes 100% of the Installed Capacity from Tucano Holding III (155 MW), a joint venture between Auren Participações and Unipar Carbocloro S.A. (50%/50%).

<sup>2</sup> The variation in generation from assets with noncontrolling ownership between the figures for the full years of 2024 and 2025 is due to extraordinary generation in 1H24, driven by higher-than-average rainfall volumes during that period. Generation was weighted by Auren's indirect economic interest.

<sup>3</sup> Adjustments detailed in the "Financial Performance" section.

## Message from Management

The year 2025 was transformational for Auren, marked by the successful execution and completion of the acquisition of AES Brasil, acquired on October 31, 2024. The transaction resulted in the creation of one of the largest energy trading companies and the third-largest energy generation company in Brazil, with 8.7 GW<sup>1</sup> of installed capacity and a portfolio balanced across hydro, wind and solar sources. The merger process was completed in just 10 months, delivering gains above the original plan and achieving key milestones ahead of schedule.

In the first quarter of 2025, we began to observe improvements in the availability of the acquired wind assets, reflecting the turnaround strategy implemented by the Company. We also initiated the Liability Management process, with the prepayment of 59% of the R\$ 5.4 billion acquisition financing. In the second quarter, all incorporated assets were integrated into Auren's performance management system, and the consolidation of the Operations Center in Bauru was completed. In the third quarter, we completed the go-live of the unified SAP system, integrated the Shared Services Center and finalized the Liability Management process, with the full early settlement of the acquisition financing. As a result, the average debt maturity was extended to 6.9 years, and the average cost of debt was significantly reduced, currently equivalent to CDI less 2.8% per year. In the fourth quarter, we completed the capture of recurring PMSO (People, Materials, Services and Others) synergies, reaching R\$ 278.7 million, above the expected annual level of R\$ 250.0 million, which had already represented more than double the R\$ 120 million initially announced at the time of the transaction. In December, average availability of the incorporated wind assets reached 94.6%, an increase of 10.6 p.p. compared to the 2024 average, achieving the 95% level one year ahead of the timeline established in the asset appraisal.

The year 2025 was also marked by a worsening of curtailment, driven by a combination of factors, including: constraints in the core transmission grid, load below expectations due to milder temperatures, higher penetration of distributed micro and mini generation, which reached 10% of total load in 4Q25, increased thermal dispatch due to new risk aversion parameters and technical improvements in pricing models. According to the National Electric System Operator (ONS), the annual average of generation cuts recorded in 2025 in the National Interconnected Grid, excluding the reimbursable portion associated with the External Unavailability Ratio (REL), reached 14.5% for wind and 21.0% for solar (vs. 6.1% and 11.2%, respectively, in 2024).

The year also saw important regulatory progress, notably the processing of Provisional Measure No. 1,304/2025 and the enactment of Law No. 15,269/2025, which established guidelines for key structural matters in the sector, including adjustments to the self-production by equivalence model, opening of the low-voltage market, formal recognition, for the first time, of compensation for generation cuts related to reliability of the SIN. For Auren, this type of curtailment represented approximately 50% of the generation cuts during the period covered by the law (September 2023 to November 2025), with an estimated impact of approximately R\$ 312.0 million, assuming full compensation. On December 31, the MME launched Public Consultation No. 210 to establish the Commitment Agreement that will enable such compensation, detailing classification criteria for generation cuts, rules for simultaneous occurrences of generation cuts of different natures, reassessment of the calculation base by the ONS and the compensation schedule.

Auren's diversified portfolio became even more important in this challenging situation. Designed to address the growing complexity of the energy sector and the increasing demand for flexibility, our portfolio of assets has consistently demonstrated resilience. Our portfolio mix during the quarter allowed us to secure R\$ 70.4 million in modulation gains, due to our hourly generation profile and price dynamics. The impact of the curtailments on net income was R\$ 207.5 million in the quarter vs. R\$ 195.5 million in 3Q25. Excluding modulation gains, the net impact in the fourth quarter totaled R\$ 137.0 million. In 2025, the curtailment impact reached R\$ 529.5 million. This effect was partially offset by modulation gains of R\$ 195.9 million recorded during the period, resulting in a net negative impact of R\$ 333.6 million.

It is important to highlight the operational performance of the wind assets in 2025. Average energy production reached 1,242 MWavg<sup>2</sup> for the year, 9.0% higher than in 2024 and equivalent to 92.9% of the 90th percentile (P90) of the assets' certified production curve. When analyzing potential generation – excluding the curtailment impact – 2025 generation would have totaled 1,469 MWavg or 100.2% of the 50 percentile (P50) and 109.7% of the 90 percentile (P90), reflecting the quality and resilience of the Company's assets.

In terms of financial performance, Adjusted EBITDA reached R\$ 1.0 billion in 4Q25, a 13.5% or R\$ 119.9 million increase on the same period last year. Adding to the Adjusted EBITDA of R\$ 3.0 billion reported in 9M25, the Company delivered Adjusted EBITDA of R\$ 4.0 billion in 2025, up 19.9% compared to 2024. This performance reflects the full commissioning of Tucano, Cajuína, Jaíba and Água Vermelha VII, improved availability of the incorporated wind assets and the capture of PMSO synergies. We ended the quarter with a leverage ratio of 4.8x (Net Debt to Adjusted EBITDA).

Excluding the impact of the recognition of the CESP Prudent Investments Indemnification (R\$ 142.8 million), Adjusted EBITDA in 4Q25 would have totaled R\$ 866.9 million, a decrease of 2.6% compared to the same period last year. The main headwinds were curtailment and GSF (67% vs. 80% in 4Q24), both at levels worse than expected by the Company and

<sup>1</sup> Installed capacity includes 50% of the capacity of Tucano Holding III (77 MW), a joint venture between Auren Participações and Unipar Carbocloro S.A. (50%/50%). Tucano Holding III's total installed capacity is 155 MW.

<sup>2</sup> Includes actual generation plus the energy to be compensated due to curtailment classified as External Unavailability ("REL"), after reaching the allowance.

the market overall. On the same basis, compared to 3Q25, Adjusted EBITDA increased 12.2%, mainly driven by hydro seasonality, with a 13.9% increase in allocated generation in the quarter, already counting the firm energy allocated in the MRE, in addition to the impact of GSF.

In its ongoing pursuit of optimization, the Company also explored additional avenues to unlock further synergies, including reallocation of energy backing to enable the execution of long-term self-production agreements, immunization of the CESP and Auren Operações pension plans and corporate reorganization.

Throughout 2025, we made significant progress in addressing the pension deficit at both CESP and Auren Operações, with the implementation of the pension plan immunization strategy (VIVEST), aligning asset returns and maturities with future liabilities, taking advantage of higher interest rates. Among the benefits of this strategy, there is the reduction of the actuarial deficit by R\$ 879 million at CESP and R\$ 112 million at Auren Operações (formerly AES Operações) as of year-end 2025 and reduction in required Company contributions by R\$ 47 million and R\$ 7 million, respectively, compared to previously projected amounts.

This preparatory work for the corporate reorganization, in turn, got underway in 3Q25, with the process to secure the required waivers, with a view to the consolidation of hydro assets under a single vehicle (CESP), a simplified corporate structure by reducing the number of publicly traded companies and greater efficiency in cash management and debt allocation. We expect to complete the restructuring process during 2026.

Lastly, on October 14, 2025, ANEEL's Executive Board approved CESP's right to receive R\$ 498.8 million in compensation for prudent investments made during the concession periods of the Jupiá, Ilha Solteira, Paraibuna and Jaguari HPPs. MME will then define the funding source, payment schedule and applicable monetary restatement index for the compensation. These topics have also been addressed in the scope of MME Public Consultation No. 190, dated July 2025. We expect this final stage to also be concluded during 2026.

Auren maintains a bullish view on long-term energy prices, projecting convergence toward the marginal cost of expansion as oversupply gradually declines through 2030. This scenario should benefit the Company over the medium and long term, particularly given its more uncontracted portfolio starting in 2028. Throughout 2025, there was a meaningful increase in the medium and long-term forward energy price curve, accompanied by substantial upward revisions to long-term assumptions by analysts and investors, who on average are now working with price levels above R\$ 200/MWh.

After a 2025 marked by intense regulatory activity and a significant increase in the power sector risk premium, an environment that highlighted the urgency of final solutions to structural challenges, early 2026 signals tangible progress in that direction. The prospect of a solution to the curtailment issue represents a relevant step forward. We believe that reducing regulatory uncertainty is essential for the power sector to regain its long-term planning capacity and mobilize the investments required to ensure economic sustainability and continued expansion of the energy matrix.

Although 2026 will still reflect part of the recent operational and regulatory pressures, the year represents an important transition period, with fundamentals beginning to point toward a more balanced outlook. From 2027 onward, we expect stronger EBITDA growth and cash generation, more fully reflecting the structural initiatives implemented since the merger with AES Brasil and accelerating the Company's deleveraging process.

Throughout 2026, we will focus on refining internal processes, completing the corporate restructuring, implementing a zero-based budget approach and continuously pursuing efficiency gains, positioning the Company to fully capture emerging opportunities.

We remain confident in the sector's attractiveness and committed to contributing to its development through technical rigor, innovation, sustainability and operational excellence. We are grateful for the trust and continued support of our customers, employees, shareholders and partners.

**Fabio Zanfelice**  
CEO

**Mateus Ferreira**  
Chief Financial and  
Investor Relations Officer

## Energy Market

4Q25 was marked by a combination of factors affecting the operation of the National Interconnected Grid (SIN), notably adverse hydrological conditions. Reservoir replenishment was below expectations at the beginning of the wet season, and hydro generation came in below the seasonal pattern estimated for the volume of firm energy allocated by MRE participants, contributing to a deterioration in GSF. In addition, the quarter was characterized by higher curtailment compared to 2024, although with a slight reduction relative to 3Q25. The average PLD in the Southeast/Midwest submarket (SE/MW) was slightly above the previous quarter, with similar levels of submarket decoupling and volatility.

Reflecting a weaker-than-historical-average start to the wet season, reservoirs ended December at 45% of maximum capacity. This level was 10 p.p. above the ten-year historical average, but 7 p.p. and 10 p.p. below December 2024 and September 2025 levels, respectively.

Milder temperatures led to load below ONS forecasts for the third consecutive quarter. The 13 p.p. year-on-year decline in GSF (67% in 4Q25 vs. 80% in 4Q24) was primarily driven by: higher allocation of MRE firm energy during the period (8 p.p. impact), lower hydro dispatch in the system (5 p.p. impact). Average generation in 4Q25 totaled 40 GWavg, compared to 43 GWavg in 4Q24.

Curtailment in 4Q25 showed a slight reduction compared to 3Q25, maintaining a downward trend throughout the quarter. October recorded the highest level in the historical series, while December posted the lowest level of cuts since April 2025. For wind generation in the SIN, total curtailment in 4Q25 reached 23.1% (3.9 GWavg), significantly above the 7.7% recorded in 4Q24 and the 20.6% reported in the third quarter of 2025. For solar generation, total curtailment in the SIN reached 23.8% (1.2 GWavg) in 4Q25, also above the 12.2% recorded in 4Q24, but substantially lower than the 33.2% observed in the third quarter of 2025.

The average PLD in the Southeast/Midwest submarket was R\$ 265/MWh in the quarter, with intraday volatility of 36%. This is slightly above the average PLD of R\$ 252/MWh in 3Q25, with similar intraday volatility (38%) and an average price of R\$ 218/MWh and intraday volatility of 33% in 4Q24. Despite a higher AML, the SE/MW submarket showed similar spreads compared to the Northeast submarket, with an average difference of R\$ 12/MWh over the third and fourth quarters of 2025 versus R\$ 11/MWh in 4Q24.

The dynamics outlined above highlight both the challenges during the quarter, especially those imposed by GSF and curtailment, and the opportunities for securing modulation gains under the current PLD dynamics. These effects will be detailed in the following paragraphs.

## Climatology

For the third consecutive quarter, temperatures in the South and Southeast/Midwest regions remained generally below the climatological average, influenced by frequent cold fronts. This pattern contrasts with the previous year, when heat waves prevailed during spring, supporting higher temperatures.

As in prior quarters, temperature behavior continued to materially impact SIN demand. Total load in 4Q25 averaged 80 GWavg, 4.2% below the level projected by ONS (PLAN 2025–2029<sup>1</sup>). On a period comparison basis, load declined 0.6% versus 4Q24, while increasing 3.1% compared to 3Q25.

Considering the full year, the SIN recorded average load of 81 GWavg in 2025, up 1.2% compared to the 2024 average. However, this figure was 2.1% below the forecast in the ONS PLAN 2025–2029. This shortfall was mainly driven by lower temperatures throughout the year in Brazil's midsouth region. In addition, weak industrial sector performance, with growth of 0.6% year-to-date through November, also contributed to the negative deviation versus the forecast.

## Natural Inflow – ENA

In 4Q25, all subsystems recorded rainfall below the climatological average, resulting in SIN ENA at 68% of the Long-Term Average (LTA). This represents the third worst result in the 94-year historical series for the quarter and characterizes an unfavorable start to the wet season.

The South subsystem, although also reporting below-average precipitation, recorded relatively stronger rainfall compared to other regions, with gross ENA equivalent to 88% of LTA. In the Southeast/Midwest subsystem, gross ENA reached 70% of LTA (vs. 93% in 4Q24 and 71% in 3Q25). The Northeast and North subsystems recorded 38% and 57% of LTA, respectively, maintaining the predominantly dry pattern observed across the country. This hydrological performance is explained by the presence of anomalous high-pressure systems, combined with cooler-than-normal waters in the equatorial Atlantic region, which reduced moisture transport from the ocean to the continent and contributed to weaker hydrological conditions during the period.

<sup>1</sup> Annual Energy Operation Planning Report 2025-2029 publication in December 2024.

**| Chart 1 | Daily Gross Natural Inflow (ENA) in the National Interconnected Grid (SIN) (GWavg)**



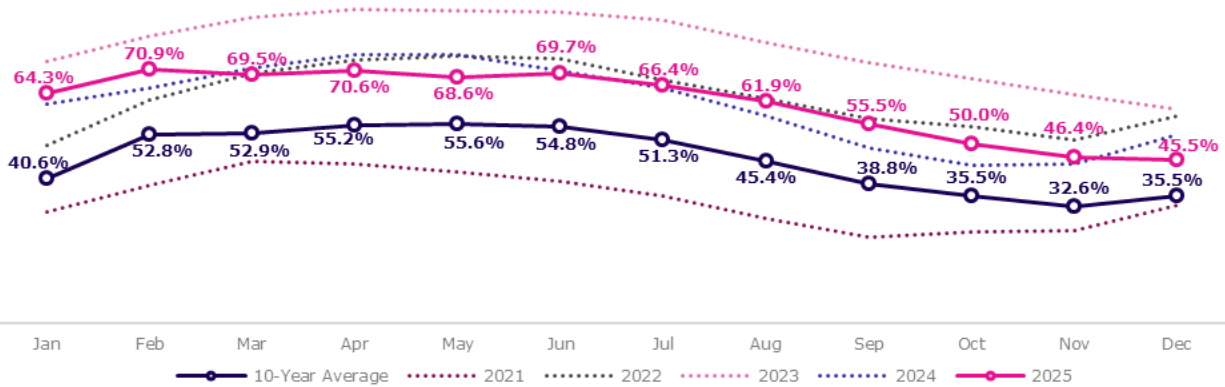
Gross ENA/ LTA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Q4	Year
2024	59%	66%	71%	86%	95%	72%	85%	57%	50%	64%	97%	101%	90%	76%
2025	98%	90%	66%	75%	71%	92%	83%	77%	75%	67%	71%	67%	68%	79%

Source: ONS

**Reservoirs, Supply-load Balance and GSF**

Throughout 2025, the adoption of new risk aversion parameters and the hybrid Newave model led the system to operate with higher marginal operating costs, increasing out-of-merit-order dispatching of thermal power plants to preserve reservoir levels. However, the deterioration in hydrological conditions observed during 4Q25 contributed to a sharper decline in reservoir levels compared to the typical seasonal pattern relative to the ten-year historical average curve. As a result, SIN storage levels closed the quarter at 45% of maximum stored energy, 10 p.p. above the ten-year historical average, but approximately 7 p.p. and 10 p.p. below December 2024 and the end of 3Q25, respectively.

**| Chart 2 | SIN Reservoir Levels (% Maximum Energy Stored)**

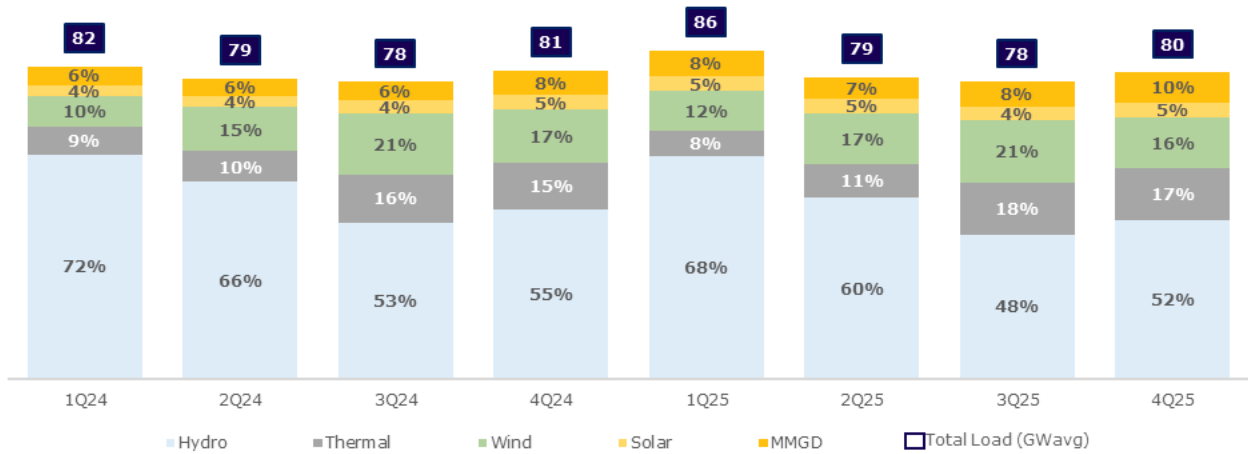


Source: ONS

Solar generation, considering both centralized plants and distributed micro and mini generation (MMGD), increased its share in meeting SIN load. It contributed 11.9 GWavg in 4Q25 (approximately 15% of total load), compared to 10.3 GWavg in 4Q24 (13% of load) and 10.0 GWavg in 3Q25 (also 13%). Wind generation maintained a virtually stable share of load supply. Its effective contribution declined by 0.8 GWavg (-1 p.p.) compared to 4Q24, despite higher potential generation between periods (16.6 GWavg in 4Q25 vs. 14.3 GWavg in 4Q24), reflecting higher curtailment during the quarter. Compared to 3Q25, wind contribution in the fourth quarter of 2025 was 3.2 GWavg lower (-5 p.p.).

At the same time, lower hydro dispatch in the quarter reduced the source’s share in load supply by 3 p.p. compared to 4Q24, while increasing 3 p.p. versus 3Q25 (Chart 3).

**| Chart 3 | Supply-Load Balance (SIN) – Contribution by Source to Load Supply (GWavg)**

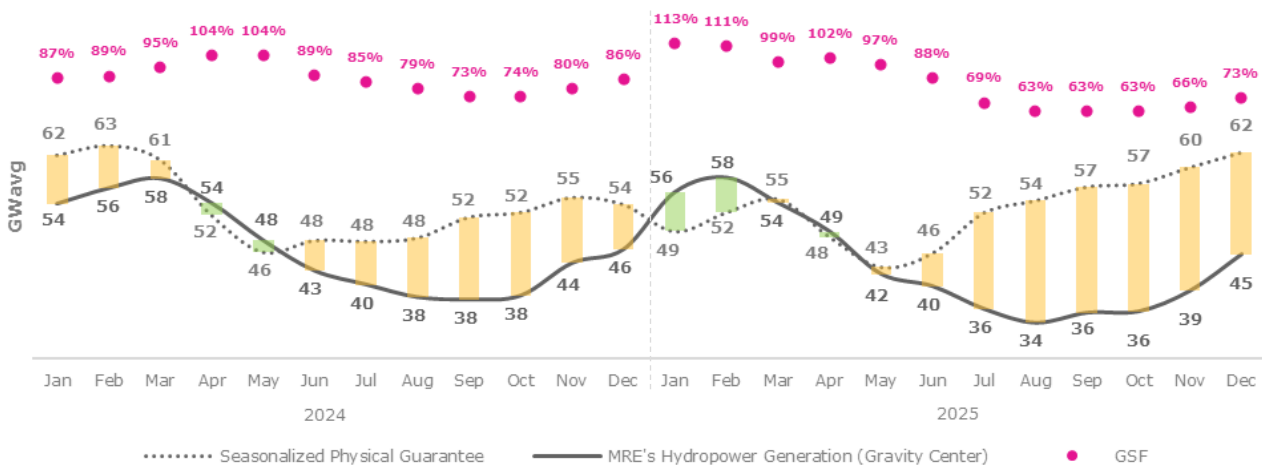


Source: ONS

As in the previous quarter, the volume of firm energy allocated in the MRE was higher in 4Q25 (60 GWavg vs. 54 GWavg in 4Q24). This expanded the reference base and, consequently, intensified hydro underperformance relative to allocated energy, as illustrated in Chart 4.

In addition, lower load and the unfavorable start to the wet season resulted in hydro generation of 40 GWavg in the quarter, below the 43 GWavg recorded in 4Q24 (-6.2%). As a result, average GSF reached 67% in 4Q25, compared to 80% in the same period of the previous year. The 13 p.p. QoQ difference is explained by the greater MRE firm energy allocation (8 p.p.) and lower hydropower generation across the system (5 p.p.).

**| Chart 4 | Hydro Displacement (% GSF)**



GSF	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Q4	Year
2023	104%	98%	102%	105%	98%	80%	78%	80%	83%	83%	83%	86%	84%	90%
2024	87%	89%	95%	104%	104%	89%	85%	79%	73%	74%	80%	86%	80%	87%
2025	113%	111%	99%	102%	97%	88%	69%	63%	63%	63%	66%	73%	67%	83%

Source: CCEE

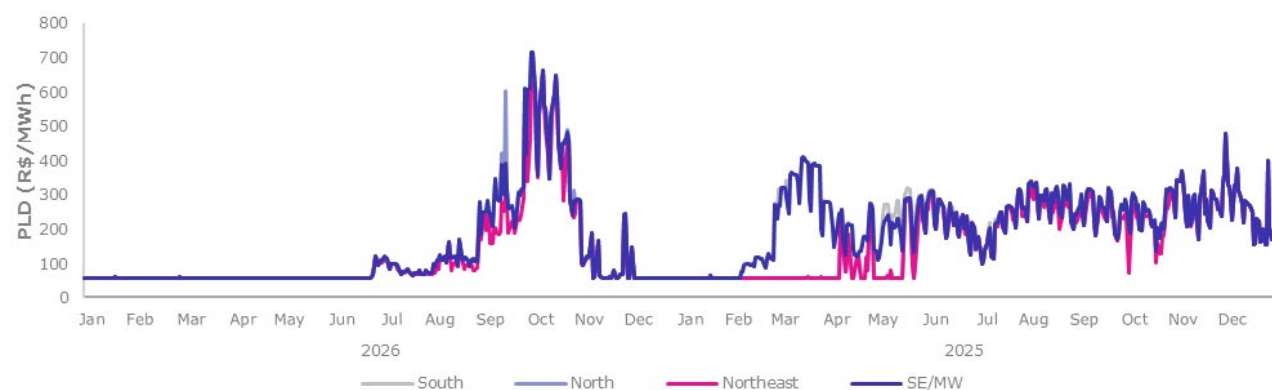
## Difference Settlement Price (PLD)

The average Difference Settlement Price (PLD) for the Southeast/Midwest (SE/MW) submarket was R\$ 265/MWh in the quarter (vs. R\$ 218/MWh in 4Q24 and R\$ 252/MWh in 3Q25). The increase of R\$ 47/MWh and R\$ 12/MWh, respectively, reflects the deterioration in hydrological conditions between the compared periods and highlights the impact of the new risk aversion parameters introduced in the price formation modeling chain, implemented to enhance system reliability. On an annual average basis, the PLD in the Southeast/Midwest (SE/MW) submarket reached R\$ 224/MWh, an increase of R\$ 96/MWh compared to 2024.

Regarding price decoupling between the SE/MW and Northeast (NE) submarkets, the average differential stood at R\$ 12/MWh in 4Q25, in line with the R\$ 12/MWh observed in 3Q25 and the R\$ 11/MWh recorded in 4Q24. On a full-year basis, however, the average decoupling between these submarkets reached R\$ 47/MWh in 2025, significantly above the R\$ 10/MWh recorded in 2024.

The low level of decoupling observed in 2024 is mainly attributed to favorable hydrological conditions in the first half of that year, which kept prices low and aligned across all submarkets during the period. This behavior was atypical, as the first half of the year typically presents the largest price differentials between SE/MW and North/Northeast, given that hydro surpluses in the North, combined with higher wind and solar supply in the Northeast, often saturate transmission capacity toward the Southeast, widening price spreads. In 2025, without the favorable conditions observed in early 2024 and with a pattern closer to historical norms, PLD once again recorded more pronounced decoupling, reflecting renewed transfer constraints between the North/Northeast and Southeast regions.

**| Chart 5 | Daily PLD by Submarket (R\$/MWh)**



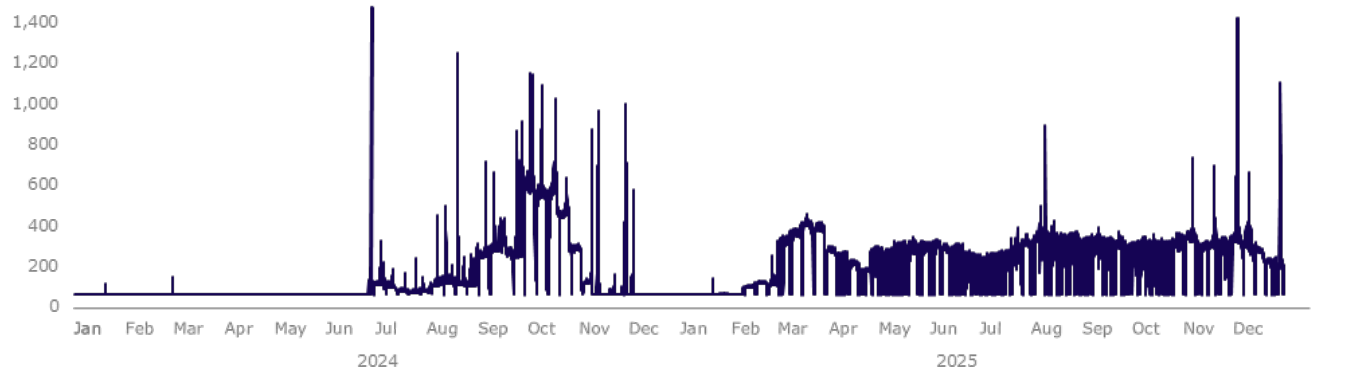
PLD by Submarket (R\$/MWh)	4Q25	4Q24	Change	2025	2024	Change
SE/MW	264.6	217.6	21.6%	224.3	128.2	75.0%
South	264.6	217.6	21.6%	226.8	128.2	77.0%
Northeast	252.9	206.7	22.3%	177.2	118.7	49.3%
North	263.8	218.2	20.9%	182.8	129.1	41.7%

Source: ONS and CCEE

Regarding the variation in energy prices throughout the day, the most significant effects of the AML increase in 4Q25 typically occur in the late afternoon and early evening, as was the case in the other quarters of the year. During certain hours, energy demand remains high while supply decreases due to the drop in total solar generation, resulting in upward pressure on prices. The opposite is observed around midday, when net load decreases significantly due to high levels of intermittent generation, pushing PLD to lower levels.

Intraday price volatility in the Southeast/Midwest (SE/MW) submarket reached 36% in 4Q25, above the 33% recorded in 4Q24 and slightly below the 38% observed in 3Q25. Three factors explain the higher volatility in 4Q25 compared to the same period of the previous year: (i) the expansion of distributed micro and mini generation (MMGD), which intensified price reductions during afternoon hours relative to the prior year; (ii) the low PLD levels observed in December 2024, driven by stronger hydrological conditions at that time; and (iii) changes in the energy price formation model. These same factors explain the difference in average annual intraday volatility, which reached 35% in 2025, compared to 24% in 2024.

**| Chart 6 | Hourly PLD – Southeast/Midwest Submarket (R\$/MWh)**



Average PLD (SE/MW)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Q4	Year
<b>2023</b>	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	80.4	74.8	84.4	74.1	<b>77.7</b>	<b>72.1</b>
<b>2024</b>	61.1	61.2	61.1	61.1	61.1	66.4	87.1	118.8	307.6	480.8	103.5	64.8	<b>217.6</b>	<b>128.2</b>
<b>2025</b>	59.2	93.7	327.3	202.2	212.6	234.7	210.0	287.2	260.3	250.2	278.2	265.9	<b>264.6</b>	<b>224.3</b>

Source: CCEE

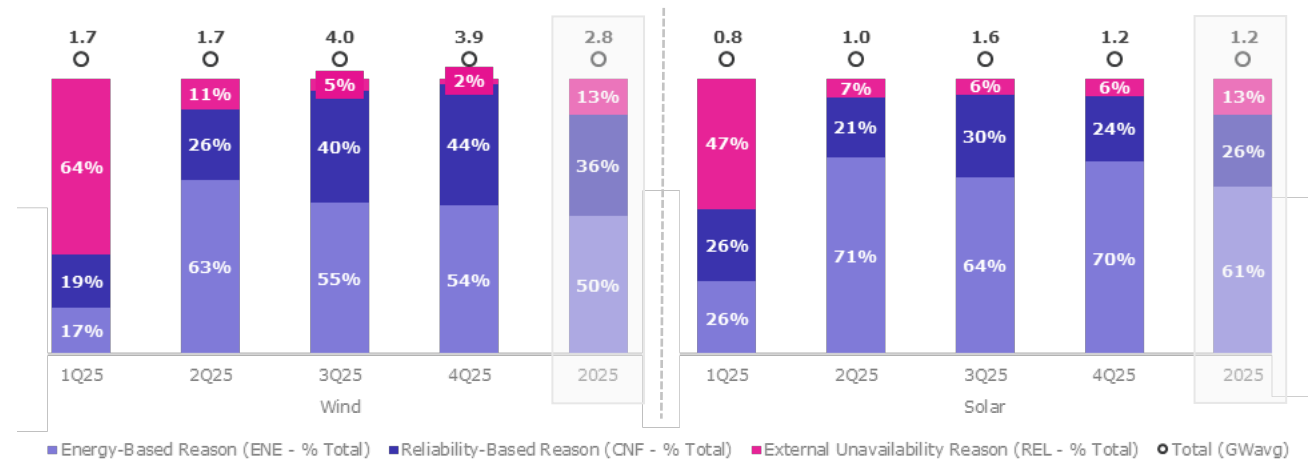
**Curtailment**

Lastly, according to ONS data, 4Q25 recorded an average total curtailment on overall SIN generation of 23.1% (3.9 GWavg) for wind generation and 23.8% (1.2 GWavg) for solar generation. Excluding events classified as External Unavailability Factor (REL), which are eligible for reimbursement, curtailment reached 22.6% (3.8 GWavg) for wind and 22.3% (1.1 GWavg) for solar.

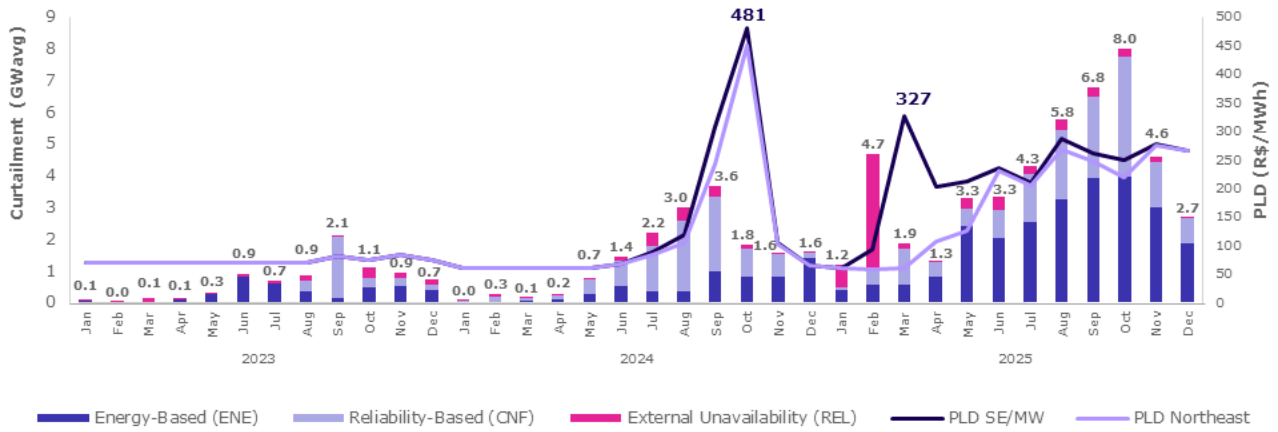
Considering total generation cuts across both wind and solar sources, for the third consecutive quarter most curtailment in 4Q25 was attributed to the Energy-Based Curtailment condition, accounting for 58% of the total. This effect reflects the combination of lower demand, driven by milder temperatures in the Southeast/Midwest and South regions, and high intermittent generation in the Northeast, in addition to increased thermal capacity and distributed micro and mini generation (MMGD), and changes in ONS risk aversion parameters. Reliability-based curtailments accounted for 39% of the total in the quarter, with October standing out, when this category reached 48%, the highest monthly level of the year.

October 2025 recorded the highest curtailment in the historical series, totaling 8.0 GWavg of restricted generation, equivalent to 29.6% of total generation.

**| Chart 7 | Percentage Share of Curtailments by Reason (GWavg, % of Total)**



**| Chart 8 | Wind and Solar Curtailment (GWavg) and PLD (R\$/MWh)**



Source: ONS/CCEE

To return to the table of contents, click [here](#).

## Performance by Business Unit

### Generation

Auren has total operational installed capacity of 8,722.8 MW, with 100% ownership in 8,098 MW, of which: 4,198 MW is from hydro, 3,023 MW from wind and 876 MWac from solar. In addition to its wholly owned assets, the Company holds noncontrolling interests in hydro assets (548 MW) and a 50% interest in the wind asset Tucano Holding III (77 MW).

### Supply-Load Balance – Generation Segment

Table 2 presents the Company's Generation Supply-Load Balance and energy purchase and sale prices. Details on Regulated Market (ACR) contracts and further information on the assets are available in Excel format in the [Results Center](#) on our Investor Relations website.

Within this segment, the Company purchases energy from third parties to manage generation portfolio fluctuations, complying with requisites such as (i) change in allocated energy due to the hydrological risk adjustment mechanism (GSF), (ii) potential compensation related to curtailment, (iii) energy sales from the assets.

4Q25 saw various significant energy backing reallocation transactions, aimed at adjusting the portfolio to formalize new long-term self-production agreements, reinforcing the long-term contracting strategy of the Company's renewable portfolio. The movements made have been summarized below:

- 169 MWavg of self-production contracts, related to the Cajuína I, II and III, Tucano and Jaíba projects, were integrated into the Supply-Load Balance. Of this total, 114 MWavg will enter supply in 2026 and 55 MWavg in 2027, with an average term of 15 years.
- 118 MWavg of purchase contracts for 2026 were formalized, aiming to reduce portfolio exposure to GSF and curtailment variations, and to replace volumes resulting from energy backing reallocation.
- New ACR sales contracts were formalized in the Existing Energy Auction, totaling 5 MWavg allocated to this segment, out of 115 MWavg contracted for supply in 2026 and 2027 in the Northeast submarket. The objective is to mitigate exposure to inter-submarket price differentials.
- Transfer of a long-term 150 MWavg USD-denominated sales contract from the Generation segment to the Commercialization segment, executed through an intercompany agreement in 2Q25. The objective was to allocate the long-term energy sales contract and its FX hedge within the same vehicle. This transfer resulted in a positive impact of R\$ 42.0 million on Generation segment EBITDA in 4Q25, in line with the previously announced effect of approximately R\$ 102 million for full-year 2025, as detailed in the [2Q25 Earnings Release](#). In 2026, this assignment will have a positive impact of R\$ 99 million for the Generation segment and a negative impact of the same magnitude for the Commercialization segment. The net effect is neutral at the consolidated EBITDA level and is already reflected in the Generation and Commercialization Supply-Load Balance.

**| Table 2 | Auren Generation Portfolio Supply-Load Balance**

Volume (MWavg)	2025	2026	2027	2028	2029	2030
<b>Own Funds (A)</b>	<b>3,374</b>	<b>3,715</b>	<b>3,777</b>	<b>3,777</b>	<b>3,777</b>	<b>3,777</b>
Firm Energy - Hydroelectric <sup>1</sup>	1,686	2,027	2,027	2,027	2,027	2,027
Firm Energy - Wind <sup>2,5</sup>	1,455	1,455	1,516	1,516	1,516	1,516
Solar Firm Energy	233	233	233	233	233	233
<b>Purchases for Resale (B)</b>	<b>1,229</b>	<b>706</b>	<b>490</b>	<b>460</b>	<b>375</b>	<b>375</b>
Conventional	515	255	119	91	6	6
Incentivized	713	452	372	370	369	369
<b>Total Funds (C = A+B)</b>	<b>4,603</b>	<b>4,422</b>	<b>4,267</b>	<b>4,237</b>	<b>4,151</b>	<b>4,151</b>
<b>Sales in ACR (D)</b>	<b>1,084</b>	<b>1,089</b>	<b>1,089</b>	<b>1,190</b>	<b>1,084</b>	<b>1,084</b>
Hydro	230	235	235	336	230	230
Wind	789	789	789	789	789	789
Solar	65	65	65	65	65	65
<b>Sales in ACL (E)</b>	<b>3,336</b>	<b>2,858</b>	<b>2,638</b>	<b>2,462</b>	<b>1,982</b>	<b>1,720</b>
Hydro <sup>3</sup>	2,469	2,087	1,822	1,647	1,166	905
Wind	698	616	671	671	671	671
Solar	170	155	144	144	144	144
<b>Total Sales (F = D+E)</b>	<b>4,420</b>	<b>3,947</b>	<b>3,726</b>	<b>3,652</b>	<b>3,065</b>	<b>2,803</b>
<b>Generation Balance (C - F)</b>	<b>183</b>	<b>475</b>	<b>541</b>	<b>585</b>	<b>1,086</b>	<b>1,348</b>
Conventional	184	369	462	421	899	1,148
Incentivized	0	106	78	165	187	200

Prices (R\$/MWh)	2025	2026	2027	2028	2029	2030
<b>Average Sale Price<sup>3</sup></b>	<b>196</b>	<b>195</b>	<b>204</b>	<b>204</b>	<b>211</b>	<b>216</b>
<b>ACR</b>	<b>265</b>	<b>275</b>	<b>276</b>	<b>274</b>	<b>277</b>	<b>277</b>
Hydro	302	309	311	295	314	314
Wind	249	258	259	259	259	259
Solar	340	353	355	355	355	355
<b>ACL</b>	<b>173</b>	<b>164</b>	<b>174</b>	<b>170</b>	<b>175</b>	<b>178</b>
Hydro	164	147	158	151	153	154
Wind	197	211	212	210	207	207
Solar <sup>6</sup>	209	212	205	201	200	198
<b>Average Purchase Price<sup>4</sup></b>	<b>194</b>	<b>180</b>	<b>180</b>	<b>177</b>	<b>182</b>	<b>182</b>
Conventional	211	144	143	133	145	145
Incentivized	182	201	192	188	182	183

<sup>1</sup> Figures include: (a) Firm Energy of proprietary assets net of the MRE adjustment factor (GSF) for the realized period through December 31, 2025 only - assume GSF equals 1 for other periods; (b) exclude energy from the Paraibuna HPP; (c) apply a 3% loss rate for assets connected to the main grid; (d) exposure of period realized until December 31, 2025 fully settled at AML and (e) firm energy subject to GSF totals 1,782 through 2028, with protection for 230 MW from the Porto Primavera HPP - in return, the Company is paying a monthly premium of R\$ 16.62/MWh. Base date: January 01, 2025.

<sup>2</sup> Includes 50% of the firm energy from Tucano Holding III, a joint venture between Auren Participações and Unipar Carbocloro S.A. This also affects the average purchase and resale prices in the respective periods.

<sup>3</sup> The hydro segment's ACL sales include a portion of incentivized energy sales, as Auren Operações is classified under the hydro segment but also executes contracts from wind assets.

<sup>4</sup> Figures are net of PIS and COFINS. They include both ACR and ACL in the average selling price, and only ACL in the average purchase price for conventional and incentivized energy. Base date: January 01, 2026. Exchange rate: R\$ 5.50/USD. The Company's energy contracts are mostly indexed to the National Broad Consumer Prices Index (IPCA).

<sup>5</sup> Assumes commercial operations start at the Cajuína 3 cluster in January 2027, adding 63 MWavg of projected firm energy.

<sup>6</sup> The equivalent price of the lease-based self-generation contract is net of PIS, COFINS and ISS.

## Operational Performance: Generation

The Company's performance throughout 2025 reinforces its efficient asset management and its strategic role in supporting the country's energy security. Its ability to adjust operations in response to climatic and market conditions highlights the resilience of Auren's portfolio and its capacity to meet system demands. The Company has therefore reaffirmed its long-term commitment to sustainability, supply reliability and value creation for shareholders and society.

**| Table 3 | Installed Capacity and Generation Output by Generation Source**

Source	Installed Capacity (MW)	Generation (MWavg)					
		4Q25	4Q24	Change	2025	2024	Change
Hydro <sup>1</sup>	4,198.4	1,812.6	2,033.1	-10.8%	1,937.7	1,831.0	5.8%
Wind <sup>2</sup>	3,100.4	1,178.2	1,238.6	-4.9%	1,242.0	1,139.6	9.0%
Solar <sup>2</sup>	876.4	178.2	189.4	-5.9%	172.8	141.0	22.5%
<b>Total Proprietary Assets</b>	<b>8,175.3</b>	<b>3,169.0</b>	<b>3,461.1</b>	<b>-8.4%</b>	<b>3,352.5</b>	<b>3,111.6</b>	<b>7.7%</b>
Interests <sup>3</sup>	547.5	305.0	307.7	-0.9%	259.4	356.0	-27.1%
<b>Total Proprietary Assets and Holdings</b>	<b>8,722.8</b>	<b>3,474.0</b>	<b>3,768.7</b>	<b>-7.8%</b>	<b>3,611.9</b>	<b>3,467.6</b>	<b>4.2%</b>

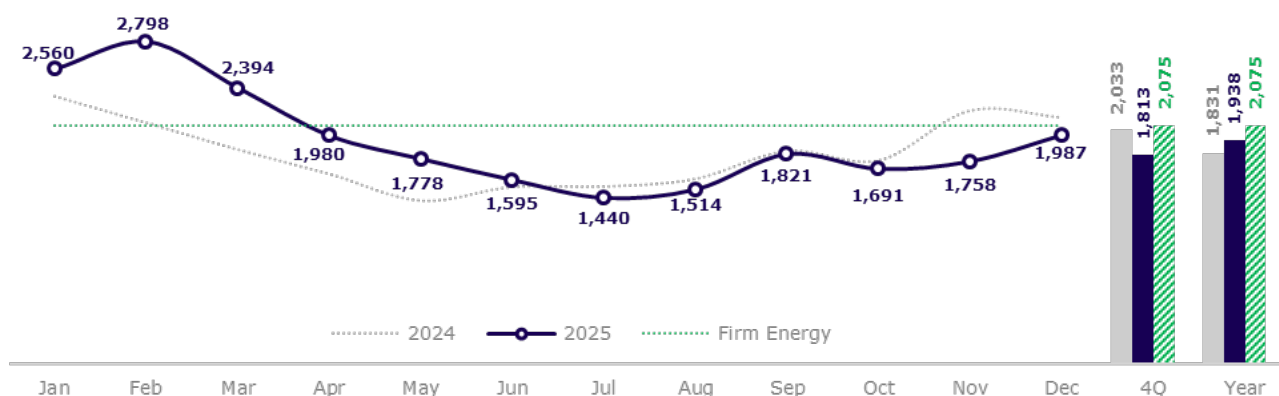
## Hydro

Auren's proprietary hydropower assets generated 1.8 GWavg in the fourth quarter of 2025, representing a 10.8% decline compared to the same period of the previous year and 12.5% below the ventures' firm energy. This performance reflects dispatch decisions by ONS aimed at managing reservoir levels and balancing the energy system, taking into account higher temperatures and the need for greater flexibility from hydro plants in the Southeast, in addition to other factors discussed in the Energy Sales section of this report.

In 2025, production reached 1.9 GWavg, a 5.8% increase over 2024 (1.8 GWavg). This positive result was driven by improved hydrological conditions in 2025 and higher energy demand to meet peak load periods. The better situation early in the year helped boost reservoir storage levels, providing greater operational flexibility for plant dispatch in the following months.

Chart 9 below shows hydro plant generation since the beginning of the year:

**| Chart 9 | Energy Generation and Firm Energy Values (MWavg)<sup>4</sup>**



<sup>1</sup> Includes generation from the Mogi-Guaçu, São José and São Joaquim SHPs. Does not include Paraibuna HPP.

<sup>2</sup> Includes actual generation plus the energy to be compensated due to curtailment classified as External Unavailability (REL), after reaching the allowance. For wind energy, this includes 50% of the Installed Capacity from Tucano Holding III (155 MW), a joint venture between Auren Participações and Unipar Carbocloro S.A. (50%/50%). For the remaining operational data of the joint venture, a 100% ownership interest is assumed.

<sup>3</sup> The data on installed capacity and generation were weighted according to Auren's indirect economic interest.

<sup>4</sup> Includes generation from the Mogi-Guaçu, São José and São Joaquim SHPs.

As shown in Table 4, by the end of 4Q25, the Verified Availability Index<sup>1</sup> remained above ANEEL's benchmark values for the main hydropower plants in the portfolio: Porto Primavera, Água Vermelha and Nova Avanhandava, which together account for 78.2% of the Company's installed hydro capacity. At the plants where availability indicators remain below benchmark levels (Promissão, Bariri and Barra Bonita), which together account for 13.1% of the Company's installed hydro capacity, the lower availability reflects specific events that occurred in prior periods, such as maintenance outages or isolated operational issues. The Company has implemented a multi-year maintenance review plan aimed at restoring asset availability to appropriate levels.

**| Table 4 | Generation and Verified Availability of Proprietary Hydro Assets**

State	Hydro	Installed Capacity (MW)	Generation (MWavg)						% Firm Energy <sup>2</sup> 4Q25	Confirmed Availability December/25	ANEEL Benchmark Index
			4Q25	4Q24	Change	2025	2024	Change			
	Porto Primavera HPP	1,540.0	823.9	957.6	-14.0%	877.9	860.9	2.0%	-7.1%	95.8%	92.3%
	Água Vermelha HPP	1,396.2	531.3	586.0	-9.3%	610.8	587.1	4.0%	-23.5%	96.6%	93.9%
	Nova Avanhandava HPP	347.4	116.7	131.0	-10.9%	119.6	94.9	26.0%	-7.0%	95.8%	94.8%
	Promissão HPP	264.0	80.0	97.8	-18.3%	86.3	71.8	20.2%	-14.8%	90.8%	94.8%
	Bariri HPP	143.1	61.2	66.3	-7.6%	56.1	49.3	13.8%	2.7%	92.0%	93.4%
SP	Barra Bonita HPP	140.8	52.5	54.0	-2.8%	41.7	36.8	13.3%	12.4%	87.2%	94.6%
	Ibitinga HPP	131.5	68.1	73.1	-6.9%	61.2	55.4	10.4%	1.9%	97.2%	93.8%
	Euclides da Cunha HPP	108.8	38.1	37.4	1.9%	39.1	37.0	5.6%	-19.1%	96.7%	94.6%
	Caconde HPP	80.4	27.7	15.8	75.1%	30.2	23.6	27.9%	-14.9%	94.3%	94.6%
	Limoeiro HPP	32.0	10.5	10.5	0.0%	11.7	10.7	8.6%	-26.6%	95.2%	94.6%
	SHPs <sup>3</sup>	14.2	2.7	3.6	-25.9%	3.2	3.4	-3.3%	-	-	-
	<b>Total</b>	<b>4,198.4</b>	<b>1,812.6</b>	<b>2,033.1</b>	<b>-10.8%</b>	<b>1,937.7</b>	<b>1,831.0</b>	<b>5.8%</b>	<b>-12.5%<sup>4</sup></b>	<b>-</b>	<b>-</b>

## Wind

Energy production from wind assets, combined with generation restrictions classified as External Unavailability (REL), which are eligible for reimbursement after exceeding the allowance threshold, totaled 1,178.2 MWavg in 4Q25, 4.9% lower than in 4Q24. This reduction reflects higher generation restrictions driven by curtailment due to Reliability (CNF) and Energy (ENE) reasons. In relation to P90 certification, energy production plus REL restrictions corresponded to 86.0% in the quarter and 92.9% for the full year. The deviation from certification was primarily caused by curtailment, as detailed in Table 5.

Potential generation, including the portion of energy not produced due to all types of curtailment, reached 111.5% of P90 and 101.6% of P50 in the quarter. October was the best month, when potential energy generation reached 113.3% of P50 and 124.2% of P90, driven by strong winds and solid turbine performance.

Energy production reached 1,242.0 MWavg in 2025, 9.0% higher than in 2024, mainly due to the full commissioning of the Tucano and Cajuína Wind Clusters and improved performance of the remaining assets.

Chart 10 presents the monthly performance of: (i) total generation – consisting of actual energy output plus the share of energy not produced due to REL restrictions (compensable); (ii) potential generation – representing actual generation plus the share of energy not produced due to various production curtailments; and (iii) the 50th and 90th percentile certification benchmark values.

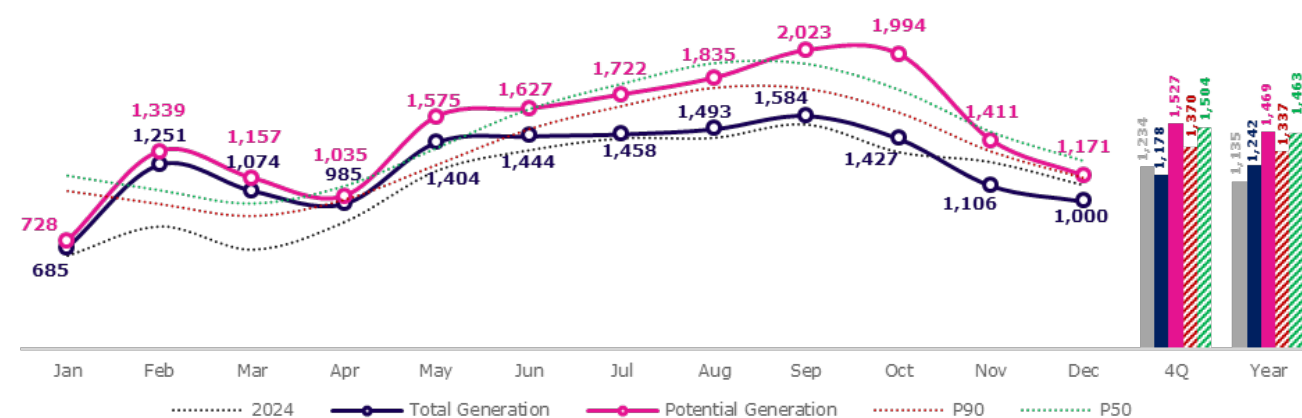
<sup>1</sup> The IDv60 (Verified Availability Index – 60 months) measures the actual operational availability of a plant compared to its benchmark capacity over the last five years.

<sup>2</sup> Percentage variation of generation above the asset's firm energy.

<sup>3</sup> Includes the combined installed capacity and energy production of the Mogi-Guaçu, São José and São Joaquim small hydro plants (SHPs). Does not include firm energy or availability data.

<sup>4</sup> Does not include data from the SHPs in the deviation versus firm energy.

**| Chart 10 | Consolidated Wind Assets – Energy Generation and Certified Values for P50 and P90 (MWavg)**



MWavg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Q4	Year
Generation 2024	626.7	826.4	667.7	856.5	1,206.2	1,345.8	1,426.4	1,429.8	1,521.3	1,332.2	1,264.7	1,107.3	<b>1,234.4</b>	<b>1,134.7</b>
Total Generation 2025 <sup>1</sup>	684.7	1,250.8	1,073.9	984.9	1,404.3	1,444.1	1,457.6	1,493.4	1,583.6	1,426.5	1,105.7	1,000.1	<b>1,178.2</b>	<b>1,242.0</b>
Potential Generation 2025 <sup>2</sup>	727.9	1,338.7	1,156.8	1,035.4	1,574.7	1,626.6	1,722.4	1,835.1	2,022.9	1,994.2	1,410.9	1,171.0	<b>1,526.6</b>	<b>1,468.5</b>

**| Table 5 | Wind Cluster Production and Performance vs. Certification**

State	Wind Clusters	Generation + Compensable Energy (MWavg)						Deviation from Certification (%)			
		4Q25		4Q24		Change		P90		P50	
		2025	2024	2025	2024	Change	2025	2024	2025	2024	
PI	Ventos do Araripe III	122.3	120.8	1.2%	156.2	153.5	1.8%	-15.2%	-7.3%	-19.9%	-12.4%
	Ventos do Piauí II	80.4	85.4	-5.8%	98.2	104.1	-5.7%	-10.1%	-5.0%	-16.2%	-11.5%
	Ventos do Araripe I	68.1	66.0	3.2%	79.8	81.2	-1.6%	-9.5%	-7.8%	-17.4%	-15.8%
	Ventos do Piauí III	75.3	75.3	0.0%	93.3	93.6	-0.3%	-11.0%	-5.6%	-17.3%	-12.3%
	Ventos do Piauí I	73.5	70.3	4.6%	94.3	90.3	4.4%	-13.2%	-3.6%	-17.9%	-8.9%
PE	Caetés	101.5	103.9	-2.3%	76.7	78.7	-2.6%	7.2%	-1.5%	-2.5%	-10.4%
RN	Cajuína	285.2	312.5	-8.7%	272.5	172.2	58.3%	-17.8%	-3.7%	-28.4%	-16.1%
	Ventus	28.2	46.5	-39.3%	31.3	33.8	-7.2%	-49.6%	-24.1%	-54.4%	-31.2%
	Salinas	16.1	21.0	-23.2%	16.2	14.2	14.0%	-30.7%	-4.1%	-36.3%	-11.8%
CE	Mandacaru	41.9	45.1	-7.1%	25.5	32.0	-20.3%	-3.8%	-9.2%	-16.4%	-21.1%
BA	Alto Sertão II	125.1	126.1	-0.9%	153.1	146.3	4.7%	-15.4%	-5.8%	-21.3%	-12.4%
	Tucano	141.8	140.8	0.7%	126.7	116.2	9.1%	-9.9%	-10.5%	-16.6%	-17.2%
RS	Cassino	18.6	24.9	-25.1%	18.0	23.5	-23.3%	-14.3%	-8.4%	-21.9%	-16.6%
<b>Total</b>		<b>1,178.2</b>	<b>1,238.6</b>	<b>-4.9%</b>	<b>1,242.0</b>	<b>1,139.6</b>	<b>9.0%</b>	<b>-14.0%</b>	<b>-7.1%</b>	<b>-21.7%</b>	<b>-15.1%</b>

4Q25 consolidated the operational recovery process of the incorporated wind clusters, demonstrating the continuity of the initiatives implemented throughout the year. Preventive, corrective and predictive maintenance routines continued to advance consistently, supported by stronger operational governance and integrated management of strategic spare parts inventories. Together, these initiatives increased equipment reliability and gradually reduced turbine downtime. By year-end, we completed the maintenance actions identified during due diligence and included in the recovery plan developed

<sup>1</sup> Total generation = energy produced + portion of energy not generated due to electrical constraint curtailment.

<sup>2</sup> Potential generation = energy produced + portion of energy not produced due to various types of restrictions imposed by the National System Operator (ONS).

between signing and closing of the AES Brasil acquisition. As a result, the incorporated farms reached the expected level of operational stability and regularity by the end of the period.

In relation to average availability in the quarter, the acquired assets reached 93.0% in 4Q25, a 2.4 p.p. improvement on the same period in 2024, as shown in Table 6. In December 2025, average availability of the incorporated assets reached 94.6%, in line with the 95% level achieved one year ahead of the timeline established during the AES Brasil integration due diligence process and aligned with our 2025 targets.

Considering all wind assets in the Company's portfolio, average availability reached 94.2% in 4Q25, an increase of 1.7 p.p. compared to the same quarter of the previous year. The YTD improvements are even more significant, with an 8.1 p.p. increase in the integrated assets and 5.7 p.p. in the total portfolio, highlighting the effectiveness of the Company's structural O&M measures and the continued consolidation of a more efficient, standardized operation.

The Tucano, Ventus and Caetés clusters demonstrated solid and consistent recovery since integration, recording improvements of 7.6 p.p., 7.0 p.p. and 4.7 p.p., respectively, in 4Q25 compared to the same period of the prior year. Following the gradual return of wind turbines to operation according to schedule, the Mandacaru complex also showed a significant improvement in availability during the fourth quarter, with an increase of 4.2 p.p. compared to 3Q25.

### | Chart 6 | Availability of Wind Clusters Acquired in 2025

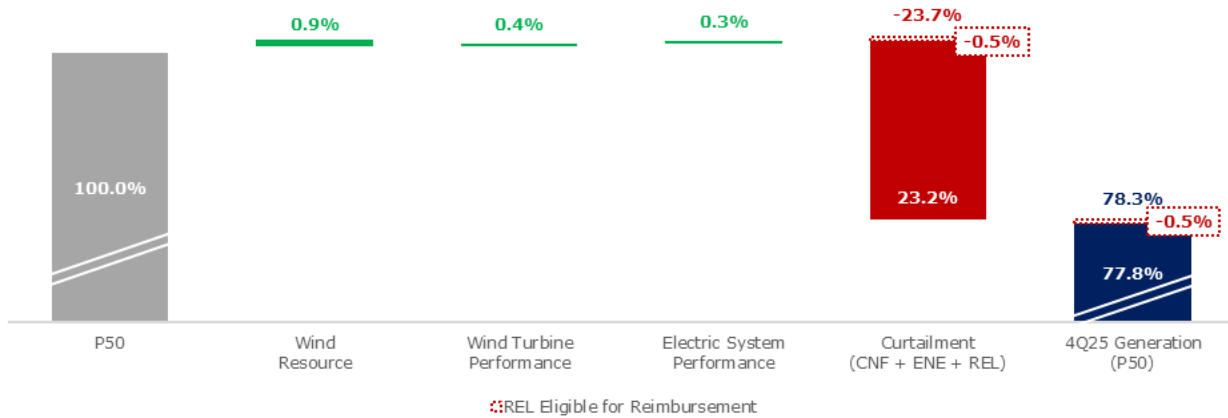
Average Availability of Acquired Assets	Q1	Q2	Q3	Q4	Year
2024	70.9%	82.9%	91.2%	90.6%	84.0%
2025	89.9%	92.0%	93.3%	93.0%	92.1%

### | Table 7 | Availability of Wind Clusters

State	Assets	Installed Capacity (MW)	4Q25	4Q24	Change (p.p.)	2025	2024	Change (p.p.)
PI	Ventos do Araripe III	357.9	96.7%	96.2%	0.5	97.1%	96.2%	1.0
	Ventos do Piauí II	211.5	97.6%	98.4%	-0.9	96.9%	98.6%	-1.7
	Ventos do Araripe I	210.0	90.9%	93.6%	-2.7	90.7%	80.5%	10.2
	Ventos do Piauí III	207.0	98.8%	97.1%	1.6	97.9%	95.7%	2.2
	Ventos do Piauí I	205.8	94.6%	95.4%	-0.8	96.6%	96.7%	-0.1
PE	Caetés	181.9	97.4%	92.7%	4.7	95.2%	93.0%	2.2
	Cajuína	685.8	94.0%	92.8%	1.1	94.3%	78.1%	16.3
RN	Ventus	187.0	95.4%	88.4%	7.0	93.1%	89.4%	3.7
	Salinas	50.4	96.0%	96.0%	0.0	95.2%	95.8%	-0.6
CE	Mandacaru	108.1	78.2%	76.7%	1.5	71.8%	81.4%	-9.7
BA	Alto Sertão II	386.1	97.9%	95.6%	2.3	97.6%	95.0%	2.6
	Tucano	322.4	88.0%	80.5%	7.6	85.7%	73.5%	12.3
RS	Cassino	64.0	88.2%	97.5%	-9.2	90.2%	97.6%	-7.5
<b>Average Availability</b>		-	<b>94.2%</b>	<b>92.5%</b>	<b>1.7</b>	<b>93.6%</b>	<b>87.9%</b>	<b>5.7</b>
<b>Average Availability Acquired Assets</b>		-	<b>93.0%</b>	<b>90.6%</b>	<b>2.4</b>	<b>92.1%</b>	<b>84.0%</b>	<b>8.1</b>

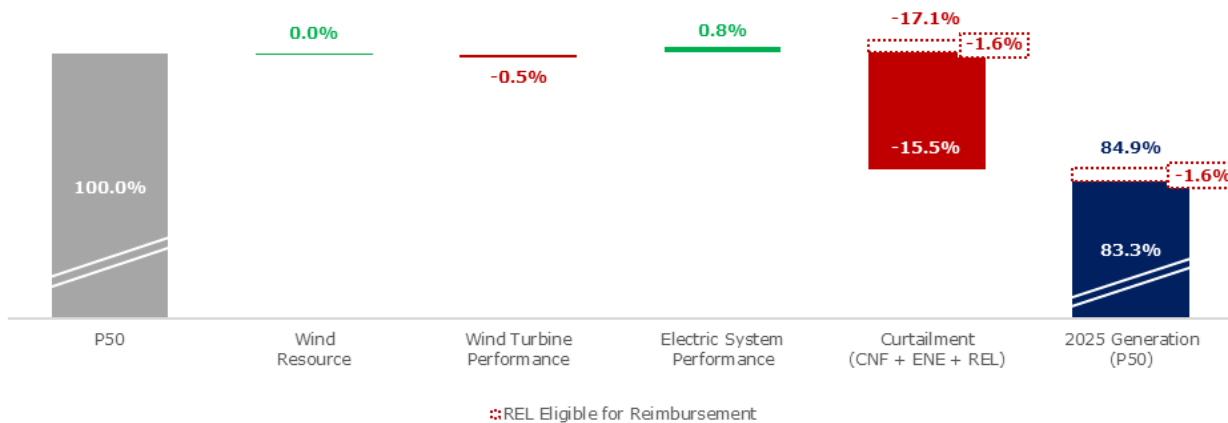
Despite stronger wind resource availability and improved turbine and electrical system performance relative to certification assumptions, energy production from the consolidated wind portfolio reached 78.3% of P50 and 86.0% of P90 in the quarter, and 84.9% of P50 and 92.9% of P90 for full-year 2025. The main culprit was curtailment, which reduced expected generation by 23.7 p.p., with 23.2 p.p. related to the non-reimbursable portion.

**| Chart 11 | Consolidated Wind Generation Performance in 4Q25 (P50 indexed to 100)<sup>1</sup>**



Similarly, on a full-year basis, curtailment represented a 17.1 p.p. reduction in generation relative to the P50 certification level, of which 1.6 p.p. are eligible for reimbursement, as shown in Graph 13. The electrical system's positive performance offset the slight deviation observed in turbine performance during the period, which was impacted by lower availability due to maintenance activities carried out as part of the asset recovery plan throughout the year. As a result, production from the consolidated wind portfolio<sup>2</sup> reached 84.9% of P50 and 92.9% of P90 for full-year 2025.

**| Chart 12 | Consolidated Wind Generation Performance in 2025 (P50 indexed to 100)<sup>3</sup>**



The initiatives implemented throughout the year, aimed at increasing the reliability and operational efficiency of the acquired assets, are reflected in a more consistent level of technical performance and availability. These advances reinforce the portfolio's resilience in the face of external variations, demonstrate the continued structural strengthening of the assets and highlight the increasing stability of indicators under the Company's direct management, marking the transition to a phase of continuous value capture with greater operational stability and robustness. Going forward, the focus will be on preserving the performance levels achieved at year-end 2025 and consolidating the structural gains delivered to date.

## Solar

The energy output from solar assets including generation curtailed due to External Unavailability (REL) subject to compensation after the allowance is met, was 178.2 MWavg in 4Q25, 5.9% less than in 4Q24. In the quarter, production was 24.6% below the expected generation defined by the farms' P90 certification and 30.9% below the average generation expectation (P50), mainly impacted by curtailment classified as Reliability (CNF) and Energy (ENE).

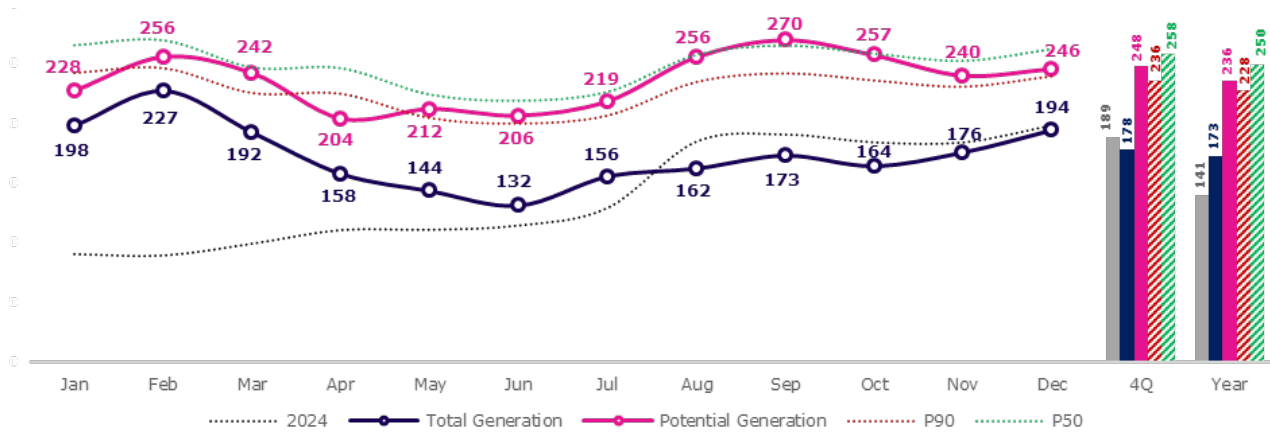
Chart 13 presents the monthly comparison of: (i) total generation – consisting of actual energy output plus the share of energy not produced due to REL restrictions (compensable); (ii) potential generation – representing actual generation plus the share of energy not produced due to various ONS-imposed restrictions; and (iii) the 50<sup>th</sup> and 90<sup>th</sup> percentile certification values.

<sup>1</sup> The curtailment figures in this subsection refer to Auren's internal data and differ from the figures presented in the "Curtailment of Auren's Wind and Solar Assets" section, which are based on data published by ONS.

<sup>2</sup> Includes actual generation plus the energy to be compensated due to curtailment classified as External Unavailability ("REL"), after reaching the allowance.

<sup>3</sup> The curtailment figures in this subsection refer to Auren's internal data and differ from the figures presented in the "Curtailment of Auren's Wind and Solar Assets" section, which are based on data published by ONS.

**| Chart 13 | Solar Assets – Energy Generation and Certified Values for P50 and P90 (MWavg)**



MWavg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Q4	Year
Generation 2024	90.0	89.0	99.0	111.0	111.0	114.0	129.0	185.0	191.0	184.0	184.0	198.0	<b>188.7</b>	<b>140.7</b>
Total Generation <sup>1</sup> 2025	198.3	227.2	192.3	157.8	143.6	131.5	155.7	162.4	173.2	164.5	175.8	194.3	<b>178.2</b>	<b>172.8</b>
Potential Generation <sup>2</sup> 2025	227.7	256.1	242.3	203.9	212.1	206.4	218.6	255.8	270.1	257.4	240.2	245.9	<b>247.9</b>	<b>236.3</b>

**| Table 8 | Solar Clusters – Energy Production and Performance vs. Certification**

Solar Clusters	Generation + Compensable Energy (MWavg)						Deviation from Certification (%)					
	4Q25			4Q24			P90			P50		
	4Q25	4Q24	Change	2025	2024	Change	4Q25	2025	4Q25	2025		
MG	Sol de Jaíba	109.5	116.8	-6.2%	102.1	68.3	49.4%	-25.4%	-29.9%	-33.1%	-37.1%	
	Guaimbê	24.3	25.0	-2.8%	25.8	28.4	-9.1%	-22.6%	-12.7%	-24.8%	-15.2%	
SP	Água Vermelha Solar	14.2	14.9	-5.0%	14.7	15.6	-5.7%	-24.0%	-14.7%	-27.8%	-19.0%	
	Boa Hora	16.6	14.4	15.3%	15.8	15.0	5.4%	-2.9%	0.5%	-7.7%	-4.5%	
	Água Vermelha VII	5.0	6.2	-18.8%	6.0	3.4	77.1%	-47.0%	-33.8%	-51.0%	-38.7%	
PI	Sol do Piauí I	8.5	12.0	-28.7%	8.4	10.4	-19.3%	-32.6%	-24.9%	-39.1%	-32.1%	
<b>Total</b>	<b>178.2</b>	<b>189.4</b>	<b>-5.9%</b>	<b>172.8</b>	<b>141.0</b>	<b>22.5%</b>	<b>-24.6%</b>	<b>-24.3%</b>	<b>-30.9%</b>	<b>-30.7%</b>		

Solar asset availability in 4Q25 reached 98.8%, a 1.2 p.p. improvement on the same period in 2024, as shown in Table 9. The result confirms the maturation of operational management and the effectiveness of initiatives aimed at reducing unavailability, directly influencing to the continuous improvement of operations and the technical performance of the assets.

<sup>1</sup> Total generation = energy produced + portion of energy not generated due to electrical constraint curtailment.

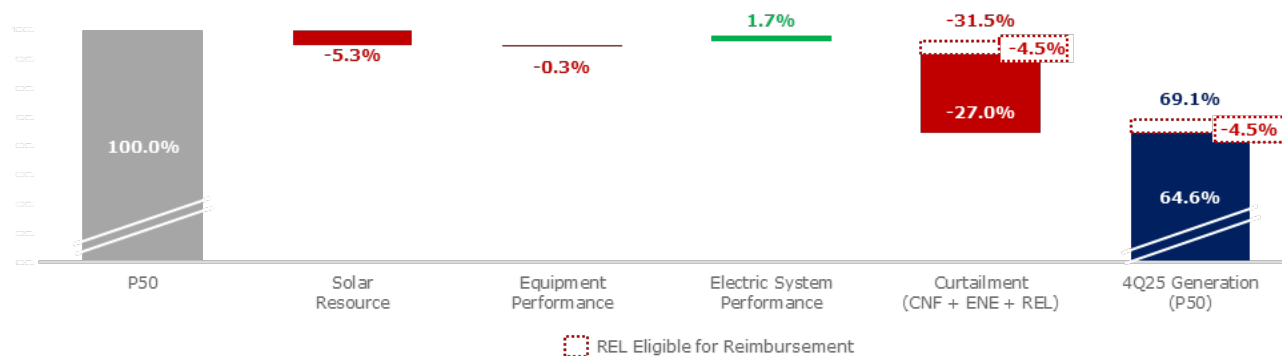
<sup>2</sup> Potential generation = energy produced + portion of energy not produced due to various types of restrictions imposed by the National System Operator (ONS).

**| Table 9 | Availability Rates of Solar Clusters**

State	Solar Clusters	Installed Capacity (MW)	Availability					
			4Q25	4Q24	Change (p.p.)	2025	2024	Change (p.p.)
MG	Sol de Jaíba <sup>1</sup>	500	99.2%	97.6%	1.6	97.9%	97.0%	1.0
	Guaimbê	150	99.0%	95.8%	3.3	98.0%	98.3%	-0.4
SP	Água Vermelha Solar	76	97.5%	99.4%	-1.9	97.5%	97.8%	-0.3
	Boa Hora	69	99.4%	99.4%	0.0	99.5%	99.5%	-0.1
	Água Vermelha VII <sup>2</sup>	33	97.7%	99.9%	-2.2	98.7%	99.2%	-0.5
PI	Sol do Piauí I	48	96.7%	96.9%	-0.2	97.8%	98.9%	-1.0
<b>Average Availability</b>		-	<b>98.8%</b>	<b>97.6%</b>	<b>1.2</b>	<b>98.0%</b>	<b>97.7%</b>	<b>0.4</b>

Overall, although solar resource levels below certification benchmarks limited generation, the main negative influence on performance during the quarter came from curtailment – particularly the non-reimbursable portion, which alone accounted for a 27.0 p.p. reduction relative to the P50. The scale of these impacts is illustrated in Chart 14.

**| Chart 14 | Consolidated Solar Generation Performance in 4Q25 (P50 indexed to 100)<sup>1</sup>**

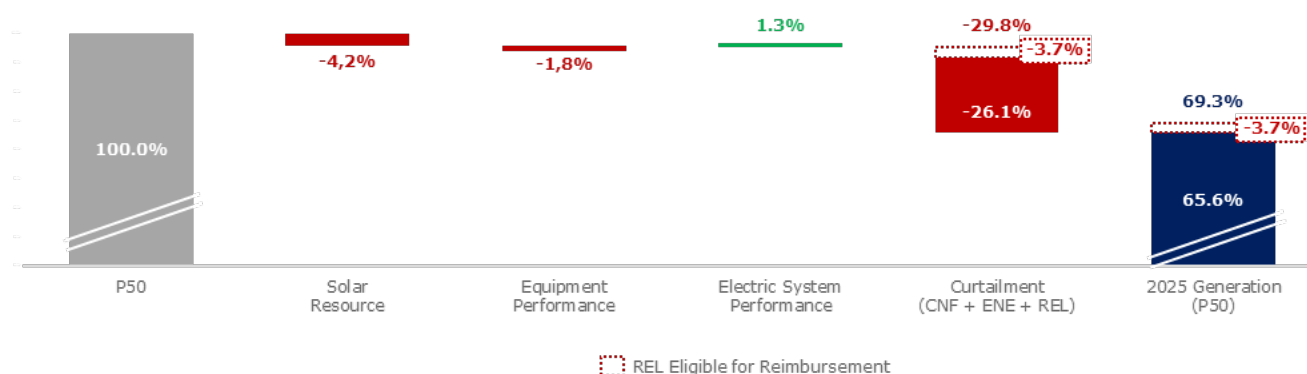


Similarly, the solar assets’ annual performance was also primarily impacted by curtailment, which accounted for a 26.1 p.p. reduction relative to the P50 certification level, considering the non-reimbursable portion. Moreover, contributing factors included weaker solar resource conditions (-4.2 p.p.) and equipment performance (-1.8 p.p.), reflecting isolated events that occurred in 1Q25, which have since been resolved by the Company. Since then, solar operations have shown continuous improvement, supported by initiatives focused on asset reliability and efficiency. The gain in electrical system performance (1.3 p.p.) reinforces this positive trend, helping to offset part of the accumulated losses. As a result, solar <sup>2</sup>generation reached 69.3% of P50 and 75.7% of P90 in the twelve months of 2025, as illustrated in Chart 15.

<sup>1</sup> The curtailment figures in this subsection refer to Auren’s internal data and differ from the figures presented in the “Curtailment of Auren’s Wind and Solar Assets” section, which are based on data published by ONS.

<sup>2</sup> Includes actual generation plus the energy to be compensated due to curtailment classified as External Unavailability (“REL”), after reaching the allowance.

**| Chart 15 | Consolidated Solar Generation Performance in 2025 (P50 indexed to 100)<sup>1</sup>**



To return to the table of contents, click [here](#).

### Curtailment and Modulation Gains Impact

**Note:** the curtailment data in this section references figures published by the ONS and differ from those in the "Wind and Solar" sections, which rely on the Company's internal estimates.

The table below presents the curtailment percentages for the wind and solar sources in Auren's portfolio, calculated as a percentage of Potential Generation and of the 50<sup>th</sup> percentile (P50). Additionally, we present the consolidated financial impact of curtailment on the Company and the benefits captured through modulation gains as a result of its diversified asset portfolio.

**| Table 10 | Curtailment and Modulation Gains**

	1Q25		2Q25		3Q25		4Q25		2025	
	Wind	Solar	Wind	Solar	Wind	Solar	Wind	Solar	Wind	Solar
<b>SIN Curtailment<sup>1</sup> (%)</b>	5.4%	9.4%	10.4%	21.1%	19.7%	31.3%	22.6%	22.3%	<b>14.5%</b>	<b>21.0%</b>
<b>Auren Curtailment<sup>2</sup> (%)</b>	8.3%	12.9%	9.0%	25.7%	18.3%	27.4%	22.3%	23.2%	<b>15.5%</b>	<b>22.4%</b>
<b>Effective Auren Generation<sup>3</sup> (% of P50)</b>	92.0%	78.7%	93.5%	62.7%	79.2%	65.3%	78.3%	69.1%	<b>84.9%</b>	<b>69.3%</b>
<b>Auren Curtailment by Source<sup>4</sup> (R\$ million)</b>	37.7	13.0	56.7	19.1	173.2	22.4	184.2	23.3	<b>451.8</b>	<b>77.6</b>
<b>Auren Consolidated Curtailment<sup>4</sup> (R\$ million)</b>	50.7		75.8		195.5		207.5		<b>529.5</b>	
<b>(-) Modulation gains (R\$ million)</b>	19.4		40.4		65.6		70.4		<b>195.9</b>	
<b>(=) Curtailment Net of Modulation<sup>4</sup> (R\$ million)</b>	31.3		35.4		130.0		137.0		<b>333.6</b>	

### Curtailment of Auren's Wind and Solar Assets

In energy terms, the total impact of non-reimbursable generation curtailments on the Company's wind and solar photovoltaic assets was 396.8 MWavg, equivalent to 22.4% of P50, of which (i) 395.3 MWavg in 4Q25 were due to Reliability-Based and Energy-Based Curtailment and (ii) 1.5 MWavg were due to External Unavailability Factor (REL) under the allowance.

For wind projects, 4Q25 recorded non-reimbursable generation curtailment totaling 342.4 MWavg, equivalent to 22.8% of P50, of which (i) 342.0 MWavg were due to Reliability-Based and Energy-Based Curtailment and (ii) 0.4 MWavg were due to External Unavailability Factor (REL) under the allowance.

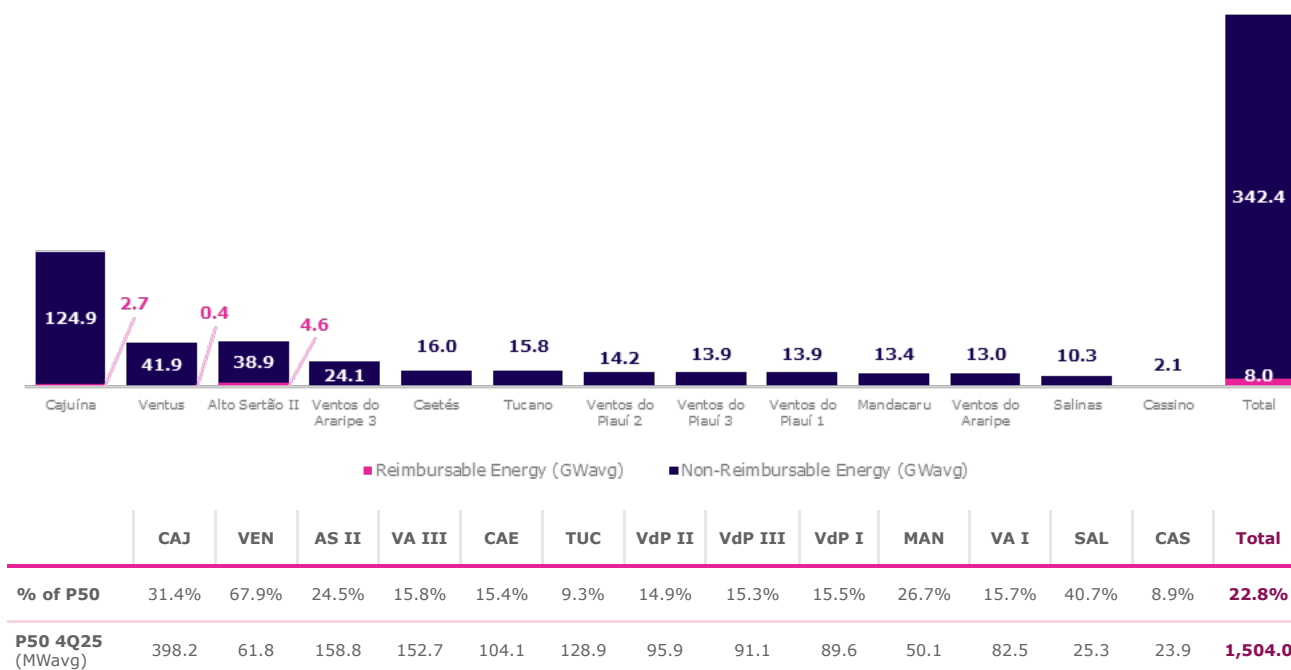
<sup>1</sup> SIN Curtailment = (Energy-Based Curtailment Energético + Reliability-Based Curtailment) / Potential Generation. Potential Generation corresponds to actual energy generation plus the energy not produced due to all types of ONS-imposed restrictions.

<sup>2</sup> Auren Curtailment (Energy-Based Curtailment + Reliability-Based Curtailment + Non-reimbursable Power Curtailment) / Potential Generation. Potential Generation corresponds to actual energy generation plus the energy not produced due to all types of ONS-imposed restrictions.

<sup>3</sup> Effective Auren Generation = (Effective Generation + Reimbursable Power Curtailment) / P50

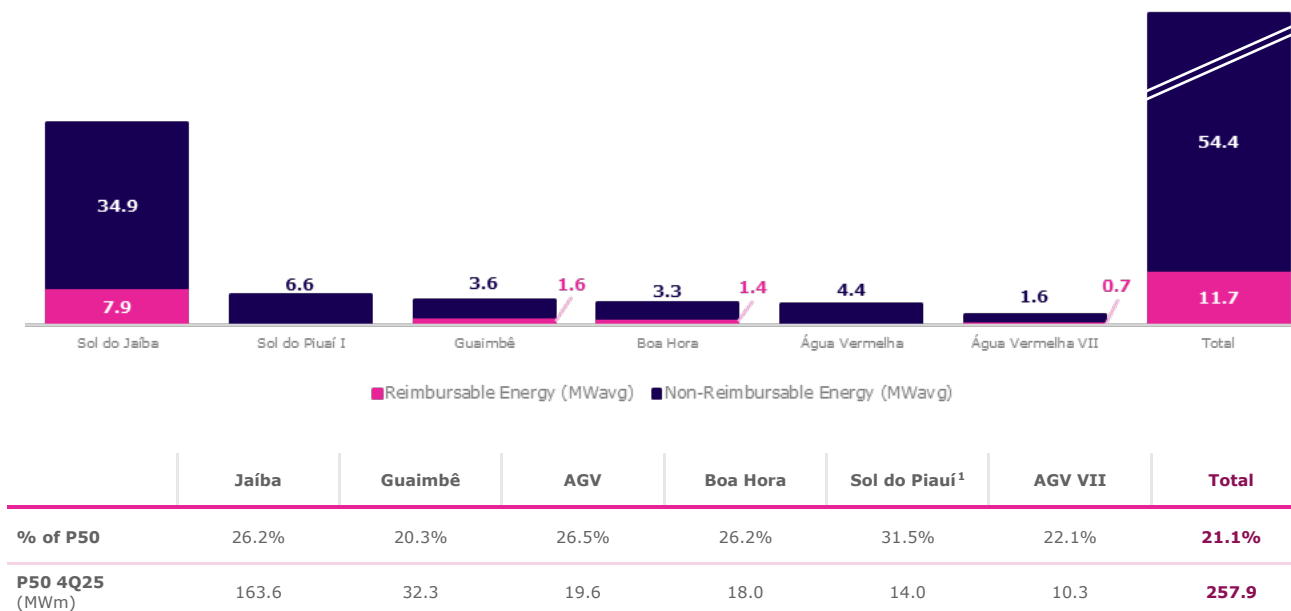
<sup>4</sup> Auren Curtailment = Energy-Based Curtailment + Reliability-Based Curtailment + Non-reimbursable Power Curtailment

| Chart 16 | Wind – Compensable and Non-Compensable Generation Curtailments in 4Q25



For solar assets, 4Q25 recorded non-reimbursable generation curtailment of 54.4 MWavg, equivalent to 21.1% of P50, of which (i) 53.3 MWavg were due to Reliability-Based and Energy-Based Curtailment and (ii) 1.0 MWavg were due to External Unavailability Factor (REL) under the allowance.

| Chart 17 | Solar – Compensable and Non-Compensable Generation Curtailments Determined by ONS in 4Q25



In financial terms, the impact of curtailment on the asset portfolio, excluding the compensable portion of REL curtailments after the allowance had been met, was R\$ 207 million, a 6% increase compared to 3Q25. R\$ 1 million of this denotes the non-compensable portion (before the hours allowance) of REL-classified curtailments, R\$ 104 million denotes reliability-based curtailments and R\$ 103 million supply curtailments. The net curtailment impact in 4Q25 was R\$ 137 million, after offsetting modulation gains of R\$ 70 million, as described below.

<sup>1</sup> The certification of Sol do Piauí is impacted by the sharing of MUST with Ventos do Piauí I.

## Generation Modulation

The Company's diversified portfolio delivered significant gains from its generation profile compared to short-term price fluctuations (PLD), since most free market (ACL) energy sales contracts have a flat profile.

Based on hourly generation and price data, modulation generated gains of approximately R\$ 70.4 million in 4Q25 and R\$ 195.9 million in 2025 for Auren.

## Financial Performance – Generation Segment

| Table 11 | Earnings for the Period

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
<b>Net Revenue</b>	<b>1,702.3</b>	<b>1,795.5</b>	<b>-5.2%</b>	<b>6,556.1</b>	<b>6,088.6</b>	<b>7.7%</b>
Power Purchase Cost	(475.6)	(550.5)	-13.6%	(1,474.5)	(1,393.6)	5.8%
Electricity Grid Usage Charges	(176.3)	(178.1)	-1.1%	(711.1)	(695.4)	2.3%
<b>Net Margin</b>	<b>1,050.4</b>	<b>1,066.9</b>	<b>-1.5%</b>	<b>4,370.5</b>	<b>3,999.7</b>	<b>9.3%</b>
<i>Net Margin</i>	61.7%	59.4%	2.3 p.p.	66.7%	65.7%	1.0 p.p.
<b>PMSO</b>	<b>(249.3)</b>	<b>(266.7)</b>	<b>-6.5%</b>	<b>(972.7)</b>	<b>(1,084.3)</b>	<b>-10.3%</b>
Other Operating Income (ORO)	468.1	1,510.9	-69.0%	473.6	1,645.6	-71.2%
<b>EBITDA</b>	<b>1,269.2</b>	<b>2,311.0</b>	<b>-45.1%</b>	<b>3,871.3</b>	<b>4,561.0</b>	<b>-15.1%</b>
NCI Dividends	130.4	93.1	40.1%	383.1	230.9	65.9%
Non-Recurring Items Related to Growth Initiatives	2.2	40.4	-94.6%	17.8	47.3	-62.4%
Accrual/(Reversal) of Provision for Litigation and Judicial Deposits	(24.8)	9.7	n.a.	(43.0)	(122.5)	-64.9%
Write-off of PPE	24.1	-	n.a.	37.3	-	n.a.
Reversal of Impairment of Property, Plant and Equipment	(325.7)	(1,500.1)	n.a.	(325.7)	(1,500.1)	n.a.
Other Adjustments	-	-	n.a.	-	21.8	n.a.
<b>Adjusted EBITDA</b>	<b>1,075.4</b>	<b>954.1</b>	<b>12.7%</b>	<b>3,940.8</b>	<b>3,238.3</b>	<b>21.7%</b>
<i>Adjusted EBITDA Margin</i>	63.2%	53.1%	10.0 p.p.	60.1%	53.2%	6.9 p.p.

In 4Q25, the **Adjusted EBITDA** for the Generation segment totaled R\$ 1,075.4 million, an increase of R\$ 121.3 million (12.7%) compared to 4Q24. The change in the period mainly reflects:

- a) **Net Margin:** R\$ 1,050.4 million in 4Q25, a 1.5% decrease compared to the same period of the previous year (R\$ 1,066.9 million), mainly due to lower hydro generation by MRE participants between periods (-6.2%) and higher curtailment at wind and solar assets. These effects were partially offset by inflation adjustments in energy sales contracts, the transfer of a 150 MWavg long-term USD-denominated sales contract from the Generation segment to the Commercialization segment (R\$ 42 million impact) and higher net modulation gains (+R\$ 23.9 million vs. 4Q24).

Compared to Net Margin in 3Q25 (R\$ 982.6 million), 4Q25 increased 6.9%, primarily driven by hydro seasonality, with a 13.9% increase in allocated generation in the quarter, considering firm energy allocation in the MRE and GSF (67% vs. 63% in 3Q25).

The R\$ 1.9 million decrease in Sector-specific Charges is explained by the reduction in average transmission and distribution rates for hydropower plants located in São Paulo state.

- b) **PMSO:** R\$ 249.3 million in 4Q25, down 6.5% on 4Q24, mainly reflecting synergies resulting from the integration process following the acquisition of AES Brasil, as mentioned in the section [Consolidated Financial Performance](#). PMSO was virtually unchanged on 3Q25 (R\$ 251.9 million or -1.0%).
- c) **ORO:** revenue of R\$ 468.1 million in 4Q25, compared with revenue of R\$ 1,510.9 million in the same period the previous year. This variation is mainly explained by the reversal of impairment of the Porto Primavera property, plant and equipment recorded in 4Q24, which added R\$ 1,500.1 million to the Generation segment result in that period, with no impact on Auren Energia's consolidated earnings.

In 4Q25, the Company recognized indemnification for CESP's Prudent Investments in the amount of R\$ 498.8 million, based on the reference dates of the expiration of the concession agreements of the Jupia, Ilha Solteira, Jaguari and Paraibuna hydro plants. This recognition occurred through the reversal of impairment in the amount of R\$ 325.7 million and the recognition of an additional R\$ 142.8 million. The remaining R\$ 30.3 million related to the total indemnification amount had already been recorded in property, plant and equipment and therefore did not impact quarterly results.

- d) **Dividends:** dividends declared by hydro assets in which the Company holds noncontrolling interests totaled R\$ 130.4 million in 4Q25, R\$ 37.3 million higher than in the same period of 2024, mainly due to extraordinary dividends from Holding Pollarix, as further detailed in the section "Auren's NCI" under [Performance by Business Unit](#).

## Auren's Noncontrolling Interests

Supply-load balance and financial information are presented on a consolidated basis for the CBA Energia, Pollarix and Pinheiro Machado holdings, in which the Company holds minority stakes and whose balances are recognized under the equity method in the Company's consolidated financial statements. Dividends from these interests are recognized in the Company's Adjusted EBITDA.

For detailed information on the corporate structure and the main characteristics of the hydro assets, please see the [Interactive Spreadsheet](#) and/or the [Modeling Guide available](#) on the Investor Relations website.

**| Table 12 | Supply-Load Balance of Hydro Assets with Noncontrolling Interests<sup>1</sup>**

Volume (MWavg)	2025	2026	2027	2028	2029
Firm Energy of assets (a)	213	256	256	256	244
Purchases (b)	72	35	5	4	4
<b>Resource (c) = (a)+(b)</b>	<b>285</b>	<b>291</b>	<b>261</b>	<b>260</b>	<b>248</b>
Sales in ACL (d)	285	256	256	256	244
<b>Requisites (e)</b>	<b>285</b>	<b>256</b>	<b>256</b>	<b>256</b>	<b>244</b>
<b>Supply-load Balance (f) = (c) - (e)</b>	<b>-</b>	<b>35</b>	<b>5</b>	<b>4</b>	<b>4</b>

Analyzing the 4Q25 Supply-Load Balance compared to 3Q25, there was a 24 MWavg reduction in the assets' firm energy for 2025, resulting from the impact of the GSF realized during the period.

Since 2Q25, the Supply-Load Balance for Noncontrolling Interests only includes energy purchase and sale transactions with the market, excluding intercompany contracts between hydropower assets and the subholdings (Pollarix, Pinheiro Machado and CBA Energia).

## Financial Performance and Dividend Payments

In this section, we present a Managerial Income Statement consolidating the financial performance of hydro assets in which Auren holds NCIs. This presentation is managerial, unaudited, and aims to help you understand the cash flow these assets generate, which ultimately results in dividend distribution to the Company.

Table 13 below highlights key items of these assets' results, jointly weighted by Auren's indirect equity interest, providing clearer insight into their operations. Note that none of the assets considered in this section carries debt on their individual balance sheets.

<sup>1</sup> Notes: (i) Firm energy of assets net of the MRE (GSF) adjustment applied; (ii) Firm energy net of internal and national grid losses (3%); (iii) Firm energy subject to hydrological risk (GSF); (iv) Reflects resources (firm energy and purchase contracts) and obligations (sales) proportional to Auren's equity interest in the NCI assets (Pollarix, CBA Energia Participações and Pinheiro Machado).

**| Table 13 | Managerial Income Statement for Hydro Assets with NCIs**

Managerial P&L Interests (R\$ million based on Auren's equity interest)	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
Volume of Energy Sold (MWavg)	285	273	4.4%	269	270	n.a.
Net Margin (R\$/MWh)	207	195	6.1%	203	181	11.9%
<b>Net Margin</b>	<b>129.7</b>	<b>117.4</b>	<b>10.5%</b>	<b>477.5</b>	<b>428.4</b>	<b>11.5%</b>
PMSO	-6.0	-6.2	-3.2%	-23.1	-21.4	7.9%
<b>Adjusted EBITDA<sup>1</sup></b>	<b>123.7</b>	<b>111.2</b>	<b>11.2%</b>	<b>454.4</b>	<b>407.0</b>	<b>11.6%</b>
Depreciation & Amortization	-9.4	-9.4	n.a.	-37.6	-37.6	n.a.
Other Results (Including MtM)	2.8	-60.4	n.a.	14.2	-10.1	n.a.
<b>EBIT</b>	<b>117.1</b>	<b>41.4</b>	<b>182.9%</b>	<b>431.0</b>	<b>359.3</b>	<b>20.0%</b>
Financial Result	7.8	-2.7	n.a.	22.3	-2.6	n.a.
<b>EBIT</b>	<b>124.9</b>	<b>38.7</b>	<b>n.a.</b>	<b>453.3</b>	<b>356.7</b>	<b>27.1%</b>
Income Tax/Social Contribution	-30.6	-31.0	-1.3%	-112.0	-108.2	3.5%
<b>Net Income<sup>2</sup></b>	<b>94.3</b>	<b>7.7</b>	<b>n.a.</b>	<b>341.3</b>	<b>248.5</b>	<b>37.3%</b>
<b>Dividends Announced</b>	<b>130.4</b>	<b>93.1</b>	<b>40.1%</b>	<b>363.7</b>	<b>230.9</b>	<b>57.5%</b>

4Q25 at a glance:

- a) **Net Margin:** this R\$ 12.3 million margin improvement is explained primarily by higher average Difference Settlement Prices (PLD) in 4Q25 compared to 4Q24 (R\$ 265/MWh vs. R\$ 218/MWh respectively), applied over the surplus volume of 41 MWavg at CBA Energia and Pollarix.
- b) **PMSO:** totaled R\$ 6.0 million in the fourth quarter of 2025 compared to R\$ 6.2 million in the same period of the previous year. The R\$ 0.2 million reduction is mainly explained by the postponement of road maintenance services at the Picada hydro plant to 2026.
- c) **Adjusted EBITDA:** R\$ 123.7 million in 4Q25, an 11.2% increase compared to the R\$ 111.2 million recorded in 4Q24, mainly driven by the R\$ 12.3 million increase in net margin.
- d) **Other Results:** other results improved by R\$ 63.2 million versus 4Q24, mainly influenced by mark-to-market (MtM) variation, reflecting the increase observed in the forward energy price curve, in addition to the accounting methodology adjustment for mark-to-market, which had generated a negative effect in 4Q24 at Enercan (+R\$ 70.8 million vs. 4Q24). This effect was partially offset by GSF reimbursements (-R\$ 7.3 million vs. 4Q24).
- e) **Financial Result:** revenue of R\$ 7.8 million in 4Q25 versus expense of R\$ 2.7 million in the same period of the previous year, mainly due to: (i) monetary restatement of the UBP balance due to the decline in the IGP-M index applied to the Picada, Baesa and Enercan HPPs (R\$ 4.6 million); and (ii) the increase in financial investment income at Pollarix Holding and Amador Aguiar SPE, driven by higher available cash in both companies (balance of R\$ 169 million in 4Q25 vs. R\$ 56 million in 4Q24) plus CDI dynamics during the period.
- f) **Announced Dividends:** R\$ 130.4 million in the fourth quarter of 2025, compared to R\$ 93.1 million in 4Q24, reflecting changes implemented in the dividend policy and in the dividend recognition method during 2025.

To return to the table of contents, click [here](#).

<sup>1</sup> Adjusted EBITDA excludes mark-to-market effects.

<sup>2</sup> Net Income reported can be found in Note 11 of Auren Energia's Financial Statements, which is the sum of the share of profit (loss) of the equity-accounted investees Pollarix, CBA Energia Participações and Pinheiro Machado Participações.

## Commercialization

### Supply-Load Balance - Commercialization Segment

Table 14 presents the Company's Commercialization Supply-Load Balance, including sales margins for 2025 and 2026. The figures reflect volumes traded through the energy trading firms Auren Comercializadora, ARN Comercializadora (formerly AES Comercializadora), Tietê Integra (formerly AES Tietê Integra), CESP Comercializadora and Esfera.

In 2025, Auren traded 6,583 MWavg of energy across end-consumer contracts and other counterparties, cementing its leadership position in Brazil's energy trading segment.

**| Table 14 | Supply-Load Balance of Auren's Commercialization Portfolio**

Volume (MWavg)	2025	2026	2027	2028	2029	2030
Purchases (A)	6,583	4,005	2,528	1,968	1,231	883
Sales <sup>(1)</sup> (B)	6,583	4,113	2,602	1,944	1,145	896
<b>Contractual Margin<sup>2</sup> (R\$/MWh)</b>	<b>4.8</b>	<b>7.7</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Commercialization Balance (A - B)</b>	<b>0</b>	<b>(108)</b>	<b>(74)</b>	<b>23</b>	<b>86</b>	<b>(13)</b>
<b>Auren Consolidated Balance<sup>3</sup></b>	<b>184</b>	<b>367</b>	<b>467</b>	<b>609</b>	<b>1,172</b>	<b>1,335</b>

When analyzing the contractual margin of the Commercialization portfolio, it is important to consider (i) the role of short-term trading operations, which typically carry lower unit margins but involve high energy volumes – this type of transaction directly affects the average contractual margin of the trading company throughout the year as trading volumes grow; and (ii) the open exposure in the Commercialization Balance, which must be marked to market. For example, the 108 MWavg short position for 2026 will be marked to market based on prevailing prices for the respective period. Finally, to reconcile the Commercialization segment result, it is necessary to add the results of the other companies within the Commercialization ecosystem that are not reflected in the Supply-Load Balance presented above.

In 4Q25, portfolio management was marked by the movements below:

- a) 2026 and 2030: reduction of the short exposure by 42 MWavg and 29 MWavg, respectively. The decrease in the 2026 position reflects the strategy adopted in light of the recent increase in short and medium-term prices.
- b) 2027: increase in the short position due to energy sales in the Existing Energy Auction held at the end of 2025, with 110 MWavg allocated to this segment out of a total of 115 MWavg in the Northeast submarket, with supply in 2026 and 2027, aiming to mitigate inter-submarket price differential risk.
- c) 2028 and 2029: expansion of the long position, reinforcing portfolio risk management and ensuring continuity of sales to end consumers.
- d) The transfer of a 150 MWavg long-term dollar-denominated power purchase agreement from the Generation segment to the Commercialization segment – executed through an intercompany agreement in 2Q25 – aimed to allocate the energy sale contract and its hedge under the same entity. This transfer had a negative impact of R\$ 42 million on the Commercialization segment in 4Q25, in line with the previously announced negative impact of R\$ 102 million on 2025. In 2026, we estimate this assignment will have a negative impact of R\$ 99 million for the trader and a positive impact of the same magnitude for the Generation segment.

Note that this transaction has no effect on the Company's consolidated EBITDA. Excluding the effect of this contract assignment, the Commercialization margin would have been approximately R\$ 6.6/MWh in 2025, compared to the reported R\$ 4.8/MWh, and R\$ 10.4/MWh in 2026, compared to the reported R\$ 7.7/MWh.

- e) From a consolidated Auren Supply-Load Balance perspective, the reduction in the long position, considering both Generation and Commercialization segments jointly, is mainly the result of energy sales through the self-production agreements executed throughout 2025.

<sup>1</sup> Includes formal contracts in ACR and ACL.

<sup>2</sup> The contractual margin is calculated as the difference between revenue and expenses under formal contracts, divided by the sales volume. It does not include the valuation of exposure. Price baseline: December 31, 2025. Exchange rate: R\$ 5.32 (BRL/USD).

<sup>3</sup> The Consolidated Supply-Load Balance embraces both segments (Generation and Commercialization).

## Financial Performance of the Commercialization Segment

| Table 15 | Earnings for the Period

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
<b>Net Revenue</b>	<b>2,916.1</b>	<b>2,602.9</b>	<b>12.0%</b>	<b>9,244.4</b>	<b>7,079.8</b>	<b>30.6%</b>
Electricity Costs	(2,874.9)	(2,599.2)	10.6%	(8,919.7)	(6,780.5)	31.5%
<b>Net Margin</b>	<b>41.2</b>	<b>3.7</b>	<b>n.a.</b>	<b>324.7</b>	<b>299.3</b>	<b>8.5%</b>
<i>Net Margin</i>	1.4%	0.1%	1.3 p.p.	3.5%	4.2%	-0.7 p.p.
<b>PMSO</b>	<b>(43.1)</b>	<b>(33.7)</b>	<b>27.7%</b>	<b>(140.5)</b>	<b>(103.9)</b>	<b>35.1%</b>
Other Operating Income (ORO)	156.1	(86.5)	n.a.	303.5	(61.1)	n.a.
<b>EBITDA</b>	<b>154.1</b>	<b>(116.5)</b>	<b>n.a.</b>	<b>487.7</b>	<b>134.2</b>	<b>n.a.</b>
Mark-to-Market Adjustment of Energy Futures	(124.8)	85.0	n.a.	(267.7)	66.9	n.a.
Other Adjustments	(52.2)	0.3	n.a.	(49.0)	1.0	n.a.
<b>Adjusted EBITDA</b>	<b>(22.8)</b>	<b>(31.3)</b>	<b>-27.1%</b>	<b>170.9</b>	<b>202.1</b>	<b>-15.4%</b>
<i>Adjusted EBITDA Margin</i>	-0.8%	-1.2%	0.4 p.p.	1.8%	2.9%	-35.2%

**Adjusted EBITDA** reached -R\$ 22.8 million in 4Q25 as compared to -R\$ 31.3 million in 4Q24. Had the aforesaid contract transfer not occurred, the Adjusted EBITDA for 4Q25 would have been R\$ 19.2 million. The variation vs. 4Q24 is mainly explained by:

- a) **Net Margin:** Excluding (i) the negative impact of R\$ 42.0 million in the Commercialization segment in 4Q25 related to the assignment of the previously mentioned 150 MWavg contract and (ii) the one-off negative effect of R\$ 49.3 million in 4Q24 from the exposure adjustment to defaulting trading counterparties, the period would show a positive variation of R\$ 33.2 million. This variation is mainly explained by higher margins in trading operations carried out during the period and by the contribution of the other companies within the Commercialization ecosystem (+R\$ 7.9 million vs. 4Q24). It is worth highlighting that, on a full-year basis, the companies within the Commercialization ecosystem not reflected in the segment's Supply-Load Balance recorded Net Margin of R\$ 55.1 million.
- b) **PMSO:** operating costs and general and administrative expenses for the Commercialization segment totaled R\$ 43.1 million in 4Q25, compared to R\$ 33.7 million in 4Q24. The variations mainly reflect the addition of Way2, with an impact of R\$ 8.4 million.
- c) **Other Operating Income (Expenses):** income of R\$ 156.1 million, primarily due to the mark-to-market of future energy sales contracts, totaling R\$ 124.8 million, the remeasurement of the initial investment in Way2 (R\$ 52.2 million), and the impairment recognized in the quarter related to investments within the Commercialization ecosystem (R\$ 13.5 million).

To return to the table of contents, click [here](#).

## Consolidated Financial Performance

### Proforma Statement of Profit or Loss

**Note:** Considering the completion of the transaction with AES Brasil Energia on 10/31/2024, to assist the market in analyzing the results and facilitate the visualization and interpretation of the Company's 3Q25 data, the figures related to the 4Q24 Quarterly Financial Information are presented in an unaudited proforma view, considering the combined operations of AES Brasil and Auren from 01/01/2024 exclusively for comparative purposes. The accounting results of Auren Energia S.A. and AES Brasil Energia S.A., as disclosed in the 2024 Quarterly Financial Statements, were accordingly consolidated by summing the figures of both companies and eliminating intercompany transactions. Additionally, reclassifications were made for comparability and better presentation purposes.

The Company emphasizes that the pro forma information (i) is for informational purposes only and was prepared solely to assist the market in simulating combined results in light of the transaction with AES Brasil, and is intended solely to facilitate the visualization and interpretation of 4Q25 data; (ii) was prepared by the Company, has not been audited or reviewed by independent auditors, and under no circumstances constitutes financial statements under applicable laws and regulations; (iii) is presented on a voluntary basis; (iv) should not be relied on for investment decisions, nor interpreted as a projection of the Company's future performance; (v) does not replace any previously disclosed audited financial information from either company; and (vi) investors are advised to conduct an independent analysis of the pro forma information, always and only in conjunction with the Company's reviewed or audited financial information.

In addition to the Generation and Commercialization segments, the results presented here include the holding & pipeline segment and eliminations. The share of profit (loss) of equity-accounted investees includes assets not controlled by the Company: (i) Auren's NCIs in hydropower assets, detailed in the section "Auren's NCIs", in the chapter [Performance by Business Unit](#), plus Auren's 50% interest in the joint venture between the Tucano wind cluster and Unipar Carbocloro S.A. (Tucano Holding III), which recorded EBITDA<sup>1</sup> of R\$ 9.4 million in 4Q25 and R\$ 42.0 million in 2025. For further information, see Note 10 to the Quarterly Financial Information.

**| Table 16 | Earnings for the Period**

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
<b>Net Revenue</b>	<b>3,801.7</b>	<b>3,598.9</b>	<b>5.6%</b>	<b>13,177.0</b>	<b>11,250.8</b>	<b>17.1%</b>
Power Purchase Cost	(2,533.8)	(2,349.8)	7.8%	(7,770.1)	(6,254.7)	24.2%
Electricity Grid Usage Charges	(173.9)	(178.6)	-2.7%	(711.7)	(705.1)	0.9%
<b>Net Margin</b>	<b>1,094.1</b>	<b>1,070.5</b>	<b>2.2%</b>	<b>4,695.1</b>	<b>4,291.0</b>	<b>9.4%</b>
<i>Net Margin</i>	28.8%	29.7%	-1.0 p.p.	35.6%	38.1%	-2.5 p.p.
<b>Costs and Expenses (PMSO)</b>	<b>(341.2)</b>	<b>(370.5)</b>	<b>-7.9%</b>	<b>(1,270.4)</b>	<b>(1,353.3)</b>	<b>-6.1%</b>
Other Operating Income (ORO)	722.0	(310.7)	n.a.	609.0	164.8	269.6%
<b>EBITDA</b>	<b>1,474.9</b>	<b>389.3</b>	<b>278.9%</b>	<b>4,033.7</b>	<b>3,102.5</b>	<b>30.0%</b>
Mark-to-Market Adjustment of Energy Futures (ORO)	(239.4)	321.2	n.a.	(127.9)	(13.1)	n.a.
NCI Dividends	130.4	93.1	40.1%	383.1	230.9	65.9%
Non-Recurring Items Related to Growth Initiatives (PMSO)	5.8	79.6	-92.7%	35.3	92.9	-61.9%
Accrual/(Reversal) of Provision for Litigation and Write-off of Judicial Deposits (ORO)	(24.4)	9.9	n.a.	(40.8)	(121.9)	-66.6%
Write-off of PPE (ORO)	40.2	-	n.a.	59.7	-	n.a.
Remeasurement of the Initial Investment Way2 (ORO)	(52.2)	-	n.a.	(52.2)	-	n.a.
Reversal of Impairment (ORO)	(325.7)	(3.2)	n.a.	(325.7)	(3.2)	n.a.
Other Adjustments (ORO)	-	-	n.a.	3.1	21.8	-86.0%
<b>Adjusted EBITDA</b>	<b>1,009.7</b>	<b>889.8</b>	<b>13.5%</b>	<b>3,968.3</b>	<b>3,309.9</b>	<b>19.9%</b>
<i>Adjusted EBITDA Margin</i>	26.6%	24.7%	1.8 p.p.	30.1%	29.4%	0.7 p.p.
Depreciation and Amortization	(477.4)	(256.9)	85.9%	(1,923.0)	(1,371.5)	40.2%
Share of Profit (Loss) of Equity-Accounted Investees	60.2	(12.7)	n.a.	205.3	156.0	31.6%
Net Financial Result	(432.0)	(547.3)	-21.1%	(2,433.9)	(1,638.5)	48.5%
<b>EBIT</b>	<b>625.6</b>	<b>(427.6)</b>	<b>n.a.</b>	<b>(117.8)</b>	<b>248.5</b>	<b>n.a.</b>
Taxes (IR/CSLL)	(271.0)	64.0	n.a.	(440.1)	(281.2)	56.5%
<b>Net Profit</b>	<b>354.7</b>	<b>(363.6)</b>	<b>n.a.</b>	<b>(557.9)</b>	<b>(32.7)</b>	<b>n.a.</b>

<sup>1</sup> Including Auren Participações' proportional interest in the joint venture.

To enhance transparency and assist investors and analysts in their evaluations, the Company provides an [Interactive Spreadsheet](#) and [Modeling Guide](#) on its Investor Relations website.

## Net Margin

Net Margin – Net Revenue less Energy Purchase Costs and Sector Charges – totaled R\$ 1,094.1 million in 4Q25, a 2.2% increase compared to 4Q24 (R\$ 1,070.5 million).

As highlighted in the respective sections addressing each business segment, the main effects influencing this result were: (i) lower hydro generation in 4Q25 and higher curtailment at wind and solar assets in the Generation segment (ii) the one-off negative effect of R\$ 49.3 million recorded in 4Q24 related to the exposure adjustment to defaulting Commercialization counterparties (iii) higher margins from Commercialization operations in the Commercialization segment in 4Q25 (iv) a R\$ 7.9 million increase in margins from other companies within the Commercialization ecosystem (v) a R\$ 37.5 million increase resulting from modulation effects (vi) the R\$ 1.9 million decrease in Sector-specific Charges is explained by the reduction in average transmission and distribution rates for hydropower plants located in São Paulo state.

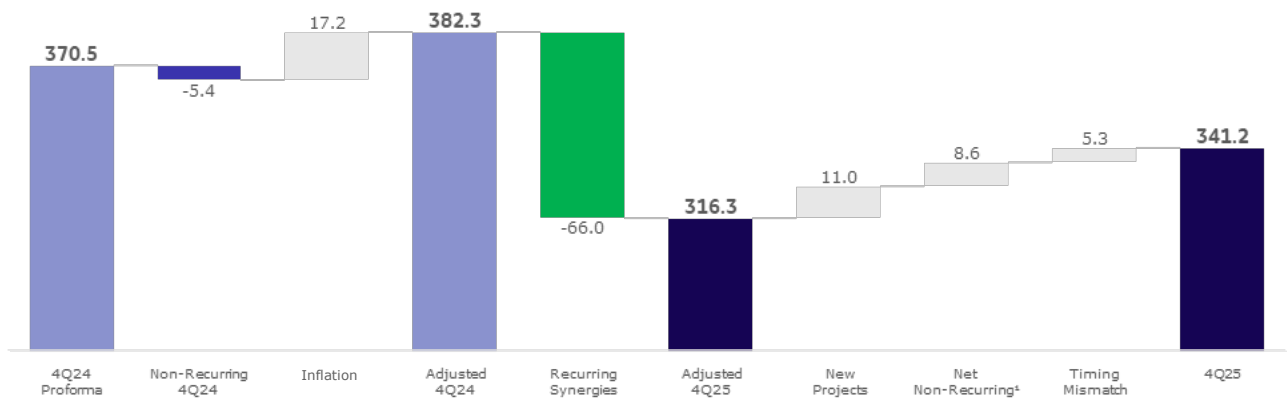
Compared to 3Q25, the R\$ 100.4 million increase is mainly explained by hydro seasonality, with higher firm energy allocation and GSF of 67% in the fourth quarter (vs. 63% in 3Q25), in addition to a R\$ 4.9 million increase in modulation gains.

## Costs and Expenses (PMSO)

Operating Costs and General and Administrative Expenses (PMSO), on a comparable basis and excluding growth initiatives and nonrecurring items, dropped by R\$ 66.0 million (17.3%) compared to 4Q24, underscoring Management’s commitment to efficiency initiatives and capturing value.

Expenses related to growth through New Projects are associated with the phased commissioning of Sol de Jaíba in 2024 (R\$ 2.6 million) and expenses related to Way2 (R\$ 8.4 million), which has been consolidated since July 2025. Regarding non-recurring items, expenses related to the merger with AES Brasil totaled R\$ 8.6 million.

| Chart 18 | Quarterly PMSO – 4Q25 x 4Q24 (R\$ million)



Total PMSO reached R\$ 341.2 million in 4Q25 vs R\$ 370.5 million in 4Q24, a nominal reduction of 7.9%. Compared to 3Q25 (R\$ 335.7 million), costs and expenses increased by 1.7%, mainly explained by the timing mismatch of expenses between periods, with certain amounts recognized in 4Q25.

The change between periods is explained by:

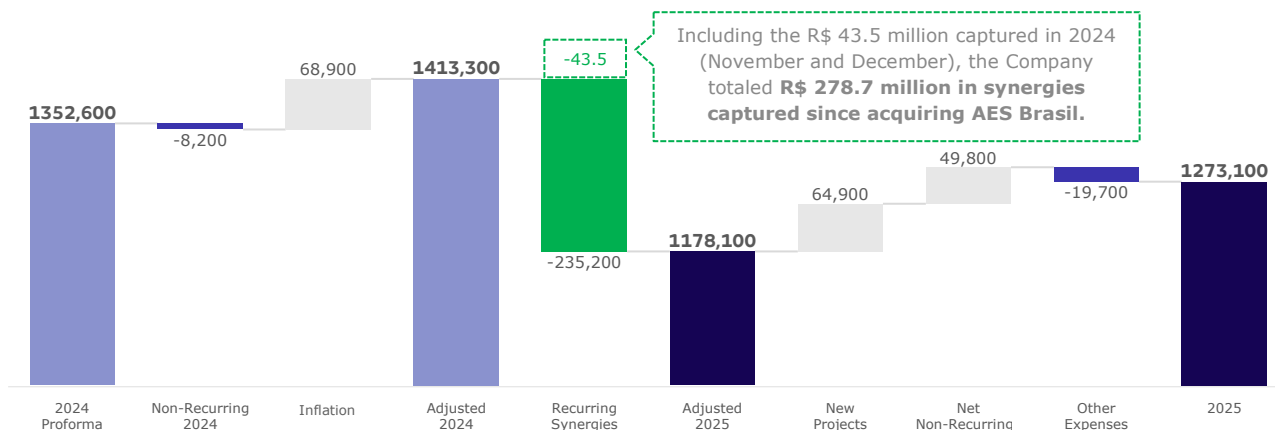
- Personnel (P):** personnel costs and expenses totaled R\$ 132.0 million in 4Q25, a nominal decrease of 3.2% compared to the same period in 2024 (R\$ 136.4 million), reflecting the synergies captured since the acquisition of AES Brasil. Compared to 3Q25 (R\$ 118.8 million), expenses increased by 11.0%, reflecting seasonality associated with the annual salary base adjustment.
- Materials and Outsourced Services (MS):** these costs totaled R\$ 153.9 million in 4Q25, a nominal reduction of 15.4% (R\$ 28.0 million vs. 4Q24 (R\$ 181.8 million), mainly due to renegotiations of and improvements to O&M contracts (R\$ 21.3 million), significant reductions in IT costs (R\$ 5.0 million), lower consulting expenses, and

<sup>1</sup> Includes non-recurring expenses related to integration efforts under the AES Brasil acquisition (layoffs, consulting, audits, legal fees, among others).

renegotiation of maintenance and engineering contracts as part of synergy initiatives. Compared to 3Q25 (R\$ 157.2 million), expenses decreased by 2.1%, reflecting the progressive capture of synergies.

- c) **Other (O):** R\$ 55.4 million in 4Q25, a 5.8% increase compared to 4Q24 (R\$ 52.3 million). This increase was primarily due to the change in the cluster lease expense accounting methodology, which has been recognized as an operating expense since 4Q24 (R\$ 5.2 million). There was also a positive impact from the renegotiation of insurance policies (R\$ 10.7 million). Compared to 3Q25 (R\$ 59.6 million), expenses decreased by 7.1%, mainly reflecting the seasonality of lease expenses in line with the generation profile.
- d) **Timing Mismatch:** an increase of R\$ 5.3 million in 4Q25, mainly due to the deferral of expenses realized in the previous quarters to the fourth quarter of 2025.

**| Chart 19 | Full year PMSO – 2025 x 2024 (R\$ million)**



Analyzing PMSO synergy capture since the closing of the AES Brasil acquisition on October 31, 2024, Auren achieved a cumulative annual reduction of R\$ 278.7 million, exceeding the previously disclosed estimated annual savings of R\$ 250.0 million, which had already represented a significant increase compared to the R\$ 120 million announced at the time of signing. With the support of an external Zero-Based Budget consulting firm, in December 2025, the Company launched a new initiative aimed at further cost optimization and capturing additional synergies starting in 2026.

### Other Operating Income (Expenses)

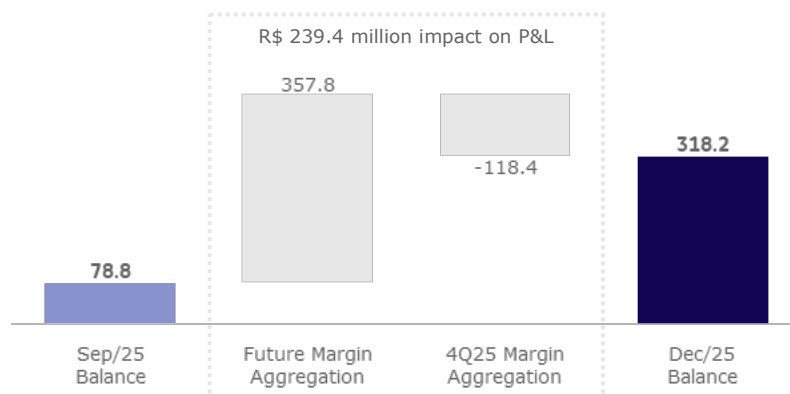
The item Other Operating Revenue (Expenses) (ORO) amounted to revenue of R\$ 722.0 million in 4Q25 compared with an expense of R\$ 310.7 million in 4Q24. The variation is mainly explained by the mark-to-market effect of future energy contracts of R\$ 239.4 million in 4Q25 and -R\$ 321.2 million in 4Q24.

In the fourth quarter of 2025, we recognized indemnification for CESP’s Prudent Investments in the amount of R\$ 498.8 million, based on the reference dates of the expiration of the concession agreements of the Jupia, Ilha Solteira, Jaguari and Paraibuna hydro plants. This recognition occurred through the reversal of impairment in the amount of R\$ 325.7 million and the recognition of an additional R\$ 142.8 million. The remaining R\$ 30.3 million related to the total indemnification amount had already been recognized in the assets’ property, plant and equipment and therefore did not impact 4Q25 results.

Chart 20 illustrates the change, throughout 4Q25, in the mark-to-market valuations for energy volumes scheduled for future delivery, with the realization of positions built in previous periods amounting to R\$ 118.4 million. As stated in recent quarterly releases, changes in future margins do not affect the contracted energy margin for the year, as reflected in the Supply-Load Balance of the Commercialization Segment. The increase in future margin reflects the upward movement of the forward energy price curve between quarters.

As previously discussed, the current accounting methodology applied to the Commercialization contracts generates quarter-to-quarter variations in the mark-to-market of projected annual energy margins. As a result, certain periods may reflect the accounting anticipation of margins that will be realized throughout the year. To reduce this effect across quarters, the Company will implement an enhancement to this methodology, effective as of 1Q26.

## | Chart 20 | Mark-to-Market Balance Throughout 2025 (R\$ million)



## Adjusted EBITDA

Auren reported an adjusted EBITDA of R\$ 1,009.7 million in 4Q25, an increase of 13.5% or R\$ 119.8 million compared with the same period the previous year. Excluding the impact of the recognition of the CESP Prudent Investments Indemnification (R\$ 142.8 million), Adjusted EBITDA in 4Q25 would have totaled R\$ 866.9 million, a decrease of 2.6% compared to the same period last year. The main headwinds were curtailment and GSF (67% vs. 80% in 4Q24) both at levels worse than expected by the Company and the market overall.

On the same basis, compared to 3Q25, there was growth of 12.2%, mainly driven by hydro seasonality, with a 13.9% increase in allocated generation in the quarter, already counting the firm energy allocated in the MRE, in addition to the impact of GSF.

The dividends declared on Auren's NCIs in 4Q25 totaled R\$ 130.4 million, fully associated with NCIs in hydropower plants, in line with the strategy to distribute dividend payments more evenly throughout the year and the extraordinary dividends received by the Pollarix holding company, as explained in greater detail in the "Auren's NCIs" section in the [Performance by Business Unit](#) chapter.

## Financial Result

| Table 17 | Consolidated Financial Result

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
Financial Revenue	319.0	313.4	1.8%	1,038.1	954.2	8.8%
Financial Expenses <sup>1</sup>	(751.0)	(860.7)	-12.7%	(3,472.1)	(2,592.7)	33.9%
<b>Net Financial Result</b>	<b>(432.0)</b>	<b>(547.3)</b>	<b>-21.1%</b>	<b>(2,433.9)</b>	<b>(1,638.5)</b>	<b>48.5%</b>

The net financial result was an expense of R\$ 432.0 million in 4Q25 compared with an expense of R\$ 547.3 million in the same period of 2024.

- a) **Financial Income:** the 1.8% increase is mainly explained by the recognition of the present value adjustment of contributions related to self-production transactions recorded in the quarter, partially offset by lower returns on financial investments due to a reduced liquidity balance (R\$ 5.5 billion in 4Q25 vs. R\$ 8.1 billion in 4Q24).
- b) **Financial Expenses:** R\$ 751.0 million in 4Q25 vs. an expense of R\$ 860.7 million in 4Q24. The R\$ 109.7 million decrease is mainly due to:
  - a. **Charges and Monetary Restatement:** the R\$ 101.3 million variance is explained mainly by the R\$ 52.3 million reduction in interest expenses and fair value on loans, and a R\$ 49.1 million QoQ drop in monetary restatement, primarily due to the reduction in gross debt between the quarters from R\$ 27.0 billion in 4Q24 to R\$ 24.5 billion in 4Q25.

Compared to 3Q25 (R\$ 625.3 million), financial expenses decreased by 30.9%, mainly due to funding costs of R\$ 103.2 million related to the 2<sup>nd</sup> and 3<sup>rd</sup> Debenture Issuances of Auren Participações, which were incurred in the third quarter.

<sup>1</sup> For comparability purposes, we highlight that the fair value effects of loans, financing, debentures and derivative financial instruments are presented net within finance costs, differing from the accounting treatment applied in the financial statements.

## Net Profit

| Table 18 | Consolidated Net Income

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 proforma	Change
<b>EBITDA</b>	<b>1,474.9</b>	<b>389.3</b>	<b>278.9%</b>	<b>4,033.7</b>	<b>3,102.5</b>	<b>30.0%</b>
Depreciation and Amortization	(477.5)	(256.9)	85.9%	(1,923.0)	(1,371.5)	40.2%
Share of Profit (Loss) of Equity-Accounted Investees	60.2	(12.7)	n.a.	205.3	156.0	31.6%
Net Finance Income (Loss)	(432.0)	(547.3)	-21.1%	(2,433.9)	(1,638.5)	48.5%
Taxes (IR/CSLL)	(271.0)	64.0	n.a.	(440.1)	(281.2)	56.5%
<b>Net Profit</b>	<b>354.7</b>	<b>(363.6)</b>	<b>n.a.</b>	<b>(557.9)</b>	<b>(32.7)</b>	<b>n.a.</b>

As a result of the aforesaid factors and changes in depreciation and amortization, equity income and taxes, the Company recorded a profit of R\$ 354.7 million in 4Q25 compared to a loss of R\$ 363.6 million in 4Q24. The main changes were as follows.

- a) **EBITDA:** Consolidated EBITDA of R\$ 1,474.9 million in 4Q25 compared to R\$ 389.3 million in 4Q24, an increase of R\$ 1,085.6 million, as previously explained.
- b) **Depreciation/Amortization:** R\$ 477.5 million in 4Q25 compared to R\$ 256.9 million in 4Q24, an increase of R\$ 220.6 million, mainly reflecting the accounting adjustment recorded in 4Q24 to align depreciation of the Porto Primavera asset to fair value (R\$ 190 million) and the amortization of the purchase price allocation (PPA) arising from the acquisition of AES Brasil, which began to be recognized as of November.
- c) **Income Tax and Social Contribution (IR/CS):** expense of R\$ 271.0 million in 4Q25, mainly driven by: (i) IR/CS paid by the Commercialization segment, (ii) IR/CS paid by renewable assets under the Presumed Profit tax basis, (iii) tax losses arising from finance costs in certain entities where no deferred tax asset was recognized.
- d) **Share of Profit (Loss) of Equity-Accounted Investees:** R\$ 60.2 million in 4Q25 vs. -R\$ 12.7 million in 4Q24. Equity income was negative in 4Q24 owing to weaker equity income, mainly due to changes in the mark-to-market of future energy contracts, with no cash impact or effect on dividends received by Auren.

## Statement of Profit or Loss by Segment

Table 19 presents the Statement of Profit or Loss for each business segment – Generation, Commercialization and Holding – along with the necessary eliminations to arrive at the consolidated result for the period.

**| Table 19 | Statement of Profit or Loss by Segment and Consolidated – 4Q25**

R\$ million	Generation	Commercialization	Holding Company	Eliminations	Consolidated
<b>Net Revenue</b>	<b>1,702.3</b>	<b>2,916.1</b>	-	<b>(816.7)</b>	<b>3,801.7</b>
Power Purchase Cost	(475.6)	(2,874.8)	-	816.7	(2,533.8)
Electricity grid usage charges	(176.3)	(0.1)	2.5	-	(173.9)
<b>Net Margin</b>	<b>1,050.4</b>	<b>41.2</b>	<b>2.5</b>	<b>-</b>	<b>1,094.1</b>
<i>Net Margin</i>	61.7%	1.4%	-	-	28.8%
<b>Costs and Expenses (PMSO)</b>	<b>(249.3)</b>	<b>(43.1)</b>	<b>(48.8)</b>	<b>-</b>	<b>(341.2)</b>
Other Operating Income (ORO)	468.1	156.1	(16.7)	114.6	722.1
<b>EBITDA</b>	<b>1,269.2</b>	<b>154.1</b>	<b>(63.1)</b>	<b>114.6</b>	<b>1,474.9</b>
Mark-to-Market Adjustment of Energy Futures (ORO)	-	(124.8)	-	(114.6)	(239.4)
NCI Dividends	130.4	-	-	-	130.4
Non-Recurring Items Related to Growth Initiatives (PMSO)	2.2	-	3.7	-	5.8
Accrual/(Reversal) of Provision for Litigation and Write-off of Judicial Deposits (ORO)	(24.8)	-	0.4	-	(24.4)
Write-off of PPE (ORO)	24.1	-	16.1	-	40.2
Reversal of Impairment (ORO)	(325.7)	-	-	-	(325.7)
Remeasurement of the Initial Investment Way2 (ORO)	-	(52.2)	-	-	(52.2)
<b>Adjusted EBITDA</b>	<b>1,075.4</b>	<b>(22.8)</b>	<b>(42.9)</b>	<b>-</b>	<b>1,009.7</b>
<i>Adjusted EBITDA Margin</i>	63.2%	-0.8%	-	-	26.6%
Depreciation and Amortization	(463.1)	(4.8)	(9.6)	-	(477.5)
Share of profit (loss) of equity-accounted investees	62.9	(2.7)	-	-	60.2
Net Finance Income (Loss)	(266.5)	16.1	(181.6)	-	(432.0)
<b>EBIT</b>	<b>602.5</b>	<b>162.8</b>	<b>(254.3)</b>	<b>114.6</b>	<b>625.6</b>
Taxes (IR/CSLL)	(202.2)	(57.4)	27.6	(39.0)	(271.0)
<b>Net Profit</b>	<b>400.3</b>	<b>105.4</b>	<b>(226.6)</b>	<b>75.7</b>	<b>354.7</b>

## Indebtedness

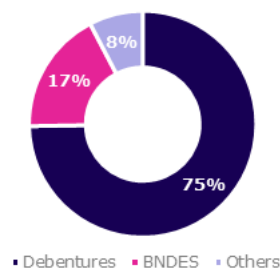
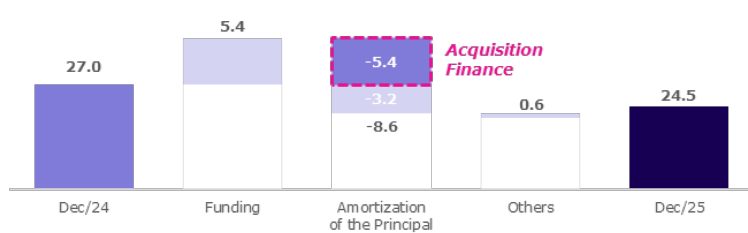
By December 31, 2025, the Company's consolidated gross debt totaled R\$ 24.5 billion, a R\$ 2.5 billion decrease compared to the December 2024 closing. Average debt maturity was extended to around 6.9 years, longer than the 5.9 years at the end of 2024.

At year-end, the Net Debt/Adjusted EBITDA ratio (leverage) reached 4.8x, a reduction of 0.9x compared to year-end 2024, mainly reflecting the results of the liability management initiatives, combined with higher asset availability and captured PMSO synergies.

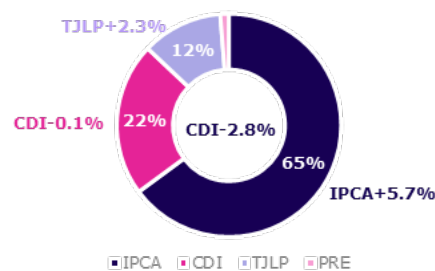
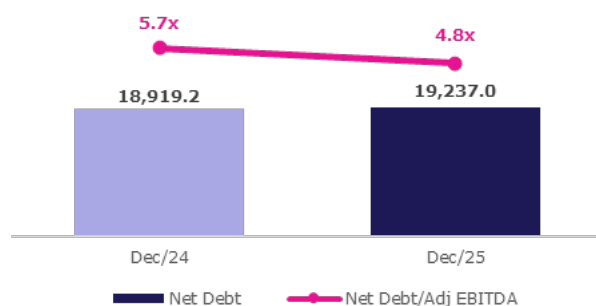
Throughout 2025, Auren successfully executed and completed its liability management strategy, supported by a continuous commitment to efficiency and disciplined capital allocation. Through funding raised on attractive terms, the Company extended the average maturity of its debt compared to year-end 2024, thereby strengthening short-term liquidity. In addition, the replacement of debt instruments with more competitive alternatives resulted in a meaningful reduction in the average cost of debt, optimizing the capital structure. Compared to 3Q25, both the average maturity and the Net Debt/Adjusted EBITDA ratio remained broadly stable.

Approximately 65% of the net debt is indexed to the IPCA, the same index that restates the Company's energy sale agreements, providing a natural hedge against future fluctuations. A small portion, representing only 22%, is indexed to CDI. The average cost of the gross debt dropped to CDI-2.8% per year.

**| Chart 21 | Changes in Debt (R\$ billion) and Gross Debt Profile**

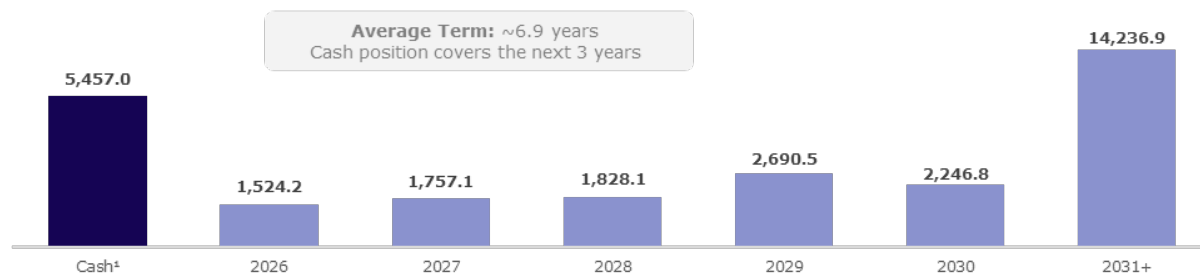


**| Chart 22 | Net Debt (R\$ million), Leverage and Net Debt Profile**



At the end of 4Q25, Auren recorded liquidity<sup>1</sup> of R\$ 5,457.0 million, a robust position that ensures full compliance of its financial obligations for the coming years. As shown in Graph 23, the liability management strategy prevented significant debt maturity concentrations in the near term.

**| Chart 23 | Amortization Schedule of the Gross Debt Principal (R\$ million)**



**| Table 20 | Debt (December 31, 2025)**

R\$ million	Dec/25	Dec/24	Change	Sep/25	Change
<b>Gross Debt</b>	<b>24,521.3</b>	<b>27,044.7</b>	<b>-9.3%</b>	<b>24,828.9</b>	<b>-1.2%</b>
Derivative Financial Instruments <sup>2</sup>	8.7	(182.6)	n.a.	90.8	-90.4%
Leases	164.1	170.6	-3.8%	166.0	-1.2%
<b>Adjusted Gross Debt<sup>3</sup></b>	<b>24,694.1</b>	<b>27,032.7</b>	<b>-8.7%</b>	<b>25,085.7</b>	<b>-1.6%</b>
Cash <sup>4</sup>	5,457.0	8,113.5	-32.7%	6,062.3	-10.0%
<b>Net Debt</b>	<b>19,237.0</b>	<b>18,919.2</b>	<b>1.7%</b>	<b>19,023.4</b>	<b>1.1%</b>
Adjusted EBITDA	3,968.3	3,309.9	19.9%	3,848.5	3.1%
<b>Net Debt/Adjusted EBITDA</b>	<b>4.8x</b>	<b>5.7x</b>	<b>-0.9x</b>	<b>4.9x</b>	<b>-0.1x</b>

For more details on the Company's indebtedness, including individual terms of each issuance, see the [Interactive Spreadsheet](#) available in Excel format in the on the Investor Relations website.

<sup>1</sup> Cash, cash equivalents, short-term investments, liquidity fund (reserve account).

<sup>2</sup> Includes mark-to-market of financial derivatives, except for those related to energy trading operations.

<sup>3</sup> Includes loans, financing and debentures, net of the related derivatives operations.

<sup>4</sup> Cash, cash equivalents, short-term investments, liquidity fund (reserve account).

## Financial Covenants – Auren Operações

At the end of December 2025, R\$ 3.8 billion of the Company's total gross debt was subject to financial covenants at the subsidiary Auren Operações, which include: (i) a leverage ceiling of 4.5x, measured by the Net Debt/Adjusted EBITDA ratio, which closed the period at 2.18x; and (ii) maintenance of the Interest Coverage Ratio (Adjusted EBITDA/Finance Costs) above 1.25x, which closed the period at 2.66x, meeting contractual obligations.

Upon completion of the corporate restructuring process, if finalized as planned, the Company will no longer have Net Debt/Adjusted EBITDA covenants in its debt structure. Upon completion of the corporate restructuring process, if finalized as planned, the Company will no longer have Net Debt/Adjusted EBITDA covenants in its debt structure.

## Ratings

During 4Q25, Fitch reaffirmed Auren's corporate rating at the highest level (AAA), maintaining a stable outlook. This decision reinforces Auren's financial strength despite its elevated leverage, reflecting the positive effects of asset integration and the agency's confidence in the Company's strategic positioning and the robustness of its financial structure.

For more details, visit the [Financial Information - Ratings](#) section on the Company's Investor Relations website.

## Free Cash Flow

**| Table 21 | Consolidated Free Cash Flow**

R\$ million	4Q25	4Q24 proforma	Change	2025	2024 Proforma	Change
Adjusted EBITDA	1,009.7	889.8	13.5%	3,968.3	3,309.9	19.9%
Non-Recurring Items Related to Growth Initiatives	(5.8)	(79.6)	-92.7%	(35.3)	(92.9)	-61.9%
IR/CS Cash	(47.8)	(12.6)	281.1%	(252.5)	(227.3)	11.1%
Working Capital and Others	(58.4)	174.5	n.a.	323.9	478.7	-32.3%
Sustaining Capex	(167.2)	(26.6)	n.a.	(353.2)	(274.3)	28.8%
<b>Operating Cash Flow (FCO)</b>	<b>730.5</b>	<b>945.5</b>	<b>-22.7%</b>	<b>3,651.2</b>	<b>3,194.1</b>	<b>14.3%</b>
Debt Service	(576.1)	(437.0)	31.8%	(2,329.7)	(1,535.2)	51.7%
<b>FCO after Debt Service</b>	<b>154.3</b>	<b>508.5</b>	<b>-69.7%</b>	<b>1,321.5</b>	<b>1,658.9</b>	<b>-20.3%</b>
Cash Conversion Ratio	15.3%	57.1%	41.9 p.p.	33.3%	50.1%	16.8 p.p.
Projects CAPEX	(299.3)	(277.7)	7.8%	(617.1)	(798.6)	-22.7%
Payment of Litigation, Liabilities and Court Settlements	(27.0)	57.4	n.a.	(77.6)	12.0	n.a.
Borrowing	174.6	7,902.8	-97.8%	5,321.1	12,099.3	-56.0%
Amortization	(696.3)	(2,030.9)	-65.7%	(8,499.5)	(3,979.2)	113.6%
Redemption from (investment into) Short-Term Investments	40.0	-	n.a.	(553.7)	-	n.a.
Capital Increase in Investees	6.0	62.2	-90.4%	(4.7)	50.9	n.a.
Dividends	-	-	n.a.	(241.8)	(492.0)	-50.8%
Acquisition of Investment	-	(6,358.7)	n.a.	(80.3)	(6,524.0)	-98.8%
Receipt on Disposal of Investees	-	-	n.a.	63.5	31.5	101.4%
Share Buyback	(5.5)	(53.6)	-89.7%	(5.5)	(53.6)	-89.7%
Investment Acquisition - Esfera	-	-	n.a.	(0.4)	(57.9)	-99.2%
<b>Free Cash Flow</b>	<b>(653.2)</b>	<b>(190.0)</b>	<b>n.a.</b>	<b>(3,374.4)</b>	<b>1,947.2</b>	<b>n.a.</b>
Opening Cash Balance	4,479.4	7,390.5	-39.4%	7,200.5	5,253.3	37.1%
<b>Closing Cash Balance</b>	<b>3,826.1</b>	<b>7,200.6</b>	<b>-46.9%</b>	<b>3,826.1</b>	<b>7,200.6</b>	<b>-46.9%</b>
Liquidity Fund – Reserve Account	1,074.6	910.3	18.1%	1,074.6	910.3	18.1%
Short-term Investments	556.3	2.6	n.a.	577.9	2.6	n.a.
<b>Closing Cash Balance + Reserve Account + Short-Term Investments</b>	<b>5,457.0</b>	<b>8,113.5</b>	<b>-32.5%</b>	<b>5,478.7</b>	<b>8,113.5</b>	<b>-32.5%</b>

Some of the main effects that influenced the variation in free cash flow between the periods are:

- Working Capital:** the reduction in working capital in the quarter compared to the previous year is mainly explained by higher reimbursement payments, totaling R\$ 83.8 million, compared to the amounts previously provisioned (R\$ 143.3 million in 4Q25).

- b) Debt Service:** R\$ 576.1 million in 4Q25. The R\$ 139.1 million increase compared to 4Q24 is mainly explained by debt issuances completed in 4Q24, with interest payments beginning in 2025, including: the 3<sup>rd</sup> Debenture Issuance of Auren Energia (R\$ 2.5 billion) and the acquisition financing, which was subsequently fully prepaid using cash on hand and proceeds from issuances related to the liability management strategy.
- c) Borrowings and Amortizations:** net balance between borrowings and amortizations was a negative R\$ 521.7 million, mainly as a result of scheduled amortization of the Company's debts. The R\$ 174.6 million fundraising completed in 4Q25 refers to the disbursement from the BNDES Climate Fund.
- d) Sustaining Capex:** maintenance-related Capex in 4Q25 totaled R\$ 167.2 million, mostly linked to the plan to improve the availability of acquired assets. Progress on these efforts is detailed in the "Generation Operational Performance" section of this report.
- e) Project Capex:** expansion-related Capex in 4Q25 totaled R\$ 299.3 million, primarily reflecting the implementation of the Cajuína 3 project. Throughout 2025, R\$ 485.4 million was invested in Cajuína 3, around 65% of projected Capex, with physical progress reaching 50.5% by the end of December.

To return to the table of contents, click [here](#).

## Other Material Information

### Immunization Strategy in the VIVEST Retirement and Pension Supplementation Plan

#### CESP Retirement and Pension Plan

In November 2025, Previc approved the new actuarial interest rate of 6.28% for the PSAP/CESP B1 plan, as previously disclosed in the [2Q25 Earnings Release](#). As a result of this approval and the immunization strategy, the actuarial deficit attributable to CESP was reduced from R\$ 1.7 billion (projection without immunization) to R\$ 929 million at year-end 2025, exceeding the Company's estimates.

The immunization strategy, implemented by Vivest throughout 2025, consisted of reallocating most of the plan's guaranteed assets to IPCA-indexed government bonds marked at amortized cost. This decision improved the asset-liability matching, reduced volatility and mitigated reinvestment risk. As a consequence, the extraordinary contributions payable by CESP in 2026 were reduced by R\$ 47 million compared to the scenario without immunization. Table 22 presents detailed findings:

**| Table 22 | CESP Previc Deficit and Extraordinary Contribution**

	Actuarial Deficit (R\$ million)	Reduction Compared to the Situation at 12/31/2024		Annual Cash Outflow of Extraordinary Contributions by CESP (R\$ million)		Reduction Compared to the Situation at 12/31/2025 No Immunization	
		(R\$ million)	Change	Current Year	Following Year	(R\$ million)	Change
<b>Realized 12/31/2024</b>	<b>1,808</b>	-	-	134	<b>137</b>		
<b>Situation at 12/31/2025</b> No Immunization Strategy	<b>1,700</b>	-108	-6%	137	<b>168</b>	-	-
<b>Realized 12/31/2025</b>	<b>929</b>	-879	-49%	137	<b>121</b>	-47	-28%

This strategy does not generate immediate impacts on the Company's financial statements, as the assets continue to be measured at fair value and the discount rate remains based on market yields of NTN-Bs. Since the immunization strategy adopts mark-to-curve accounting, it does not change these measurement criteria and therefore does not produce immediate accounting effects.

**| Table 23 | CESP Actuarial Deficit – CPC33 Methodology**

CESP Actuarial Deficit – CPC33 Methodology	12/31/2025	12/31/2024
Estimated Actuarial Deficit (R\$ million)	918	841

#### Auren Operações Retirement and Pension Plan

Similar to the strategy adopted at CESP, the Company approved the change of the PSAP/Auren Operações plan index from IGP-DI to IPCA and initiated the immunization process in December 2025, aligning asset returns and maturities with the plan's future liabilities.

As a result of the immunization, Auren Operações' actuarial deficit was reduced by R\$ 112 million and the projected increase in annual extraordinary contributions was avoided, generating savings of R\$ 7 million per year starting in 2026. Although the change in the plan's index was internally approved in November 2025, its effects remain subject to formal approval by Previc, which has up to 55 business days to issue its decision from the date of submission, filed by the Company on December 29, 2025. The results are shown in Table 24.

**| Table 24 | CESP Previc Deficit and Extraordinary Contribution**

	Actuarial Deficit (R\$ million)	Reduction Compared to the Situation at 12/31/2024		Annual Cash Outflow of Extraordinary Contributions by CESP (R\$ million)		Reduction Compared to the Situation at 12/31/2025 No Immunization	
		(R\$ million)	%	Current Year	Following Year	(R\$ million)	%
<b>Realized 12/31/2024</b>	<b>155</b>	-	-	8	<b>8</b>		
<b>Situation at 12/31/2025</b> No Immunization Strategy	<b>117</b>	-38	-25%	8	<b>12</b>	-	-
<b>Realized 12/31/2025</b>	<b>43</b>	-112	-72%	8	<b>5</b>	-7	-58%

**| Table 25 | Auren Operações' Actuarial Deficit – CPC33 Methodology**

Auren Operações Actuarial Deficit under CPC 33 Methodology	12/31/2025	12/31/2024
Actuarial Deficit (R\$ million)	23.9	18.9

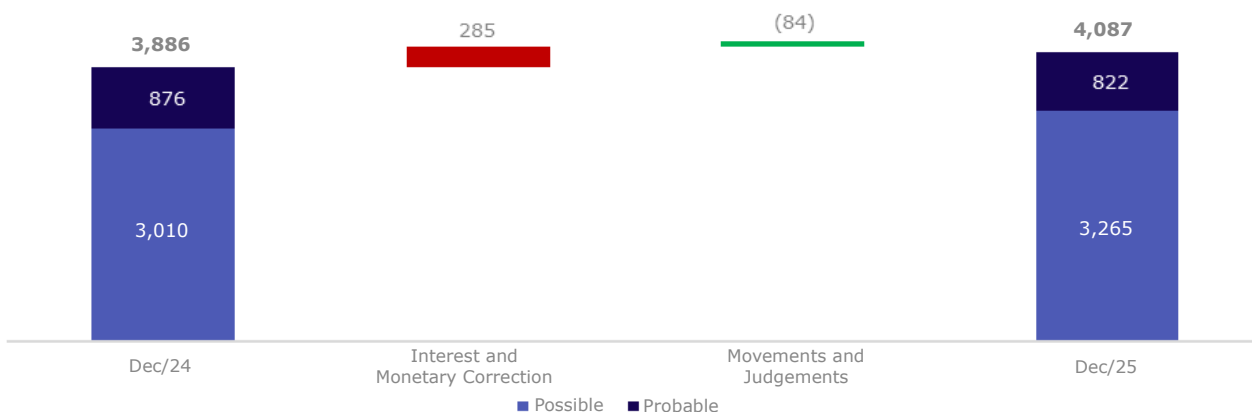
**Contingent Liabilities**

In line with market best practices, Auren discloses its contingent liabilities covering both probable and possible loss estimates.

The Company is currently party to lawsuits totaling R\$ 822 million in provisions (probable losses) and R\$ 3,265 million in contingencies classified as possible losses. The consolidated amount of R\$ 4,087 million represents a R\$ 200 million increase compared to the fourth quarter of 2024, mainly reflecting inflation adjustments and procedural developments (Chart 24).

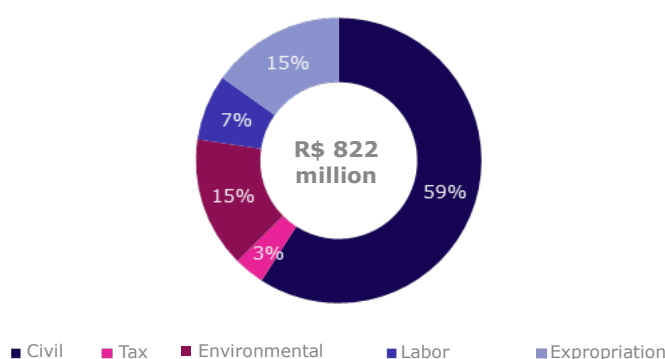
The breakdown of risk by legal nature (Chart 25, "Contingent Liabilities by Profile") shows that civil cases represent 59% of probable risk. These mostly include indemnification claims as well as regulatory and real estate disputes (excluding expropriation cases), with a total of 1,198 ongoing lawsuits.

**| Chart 24 | Contingent Liabilities – Probable and Possible (% of Total)**



Of the movements and judgments totaling R\$ 84 million in 2025, as presented in Chart 24, R\$ 78 million entailed a cash outflow.

**| Chart 25 | Contingent Liabilities by Legal Profile (% of Total)**



Auren emphasizes that the value of contingent liabilities is regularly reviewed, as its measurement is indexed to the Company's best risk prognosis, including the progression of court cases.