MACQUARIE University SYDNEY · AUSTRALIA

BUSINESS ANALYTICS PROJECT (BUSA8031)

CLIENT REPORT

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Executive Summary

This report delivers a comprehensive, data-driven analysis of Australia's National Electricity Market (NEM) as it transitions toward a decarbonized future. Drawing on detailed market, bidding, and emissions data from 2011 to April 2025, our study assesses the progress of decarbonization, regional market dynamics, bidding behaviours, and investment implications for key generation technologies such as solar, OCGT, and black coal.

Our findings confirm that the NEM is on a clear downward trajectory in emissions intensity, with the sector expected to meet or even exceed the legislated 2030 emissions reduction target. This achievement is underpinned by rapid growth in renewables, particularly solar and wind, and declining reliance on coal-fired generation. However, the transition is not uniform across regions. Southern states like South Australia and Tasmania lead in emissions reduction and renewable integration, while Queensland and Victoria continue to face transition risks due to entrenched coal generation.

Detailed analysis of bidding behaviour and price dynamics reveals that solar is increasingly exposed to price cannibalization, with higher solar penetration resulting in lower average market prices and reduced revenue stability. In contrast, OCGT assets benefit from price volatility and scarcity events, offering high potential returns but also significant risk. Black coal, while maintaining some market share, faces mounting pressure from policy, economics, and social license, with the threat of asset stranding intensifying as decarbonization accelerates.

Scenario modelling demonstrates that policy-driven shifts such as accelerated solar adoption or expedited coal retirement can profoundly reshape market structure, risk profiles, and revenue outcomes. Break-even and risk-return analyses further highlight the growing importance of portfolio diversification, system flexibility, and innovation in storage and demand-side solutions.

Based on these insights, the report recommends that investors prioritize renewables, particularly when combined with storage and firming solutions, to align with policy trends and market opportunities. Retaining some exposure to peaking assets like OCGT remains valuable for risk management in a volatile market. Conversely, investors should reduce or avoid exposure to coal assets, anticipating accelerated phase-out and regulatory intervention. Active monitoring of policy, technological advances, and emerging market mechanisms will be critical to capture new value streams and sustain long-term investment success in Australia's evolving electricity market.

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Introduction

The Australian National Electricity Market (NEM) stands at the center of the nation's energy transition, facing both unprecedented challenges and opportunities as it pursues ambitious decarbonization targets. Against the backdrop of the Paris Agreement and Australia's own policy commitments, understanding the evolution of carbon emissions intensity and generation mix has never been more vital. The rapid uptake of renewables, retirement of legacy coal assets, and integration of new technologies are reshaping the fundamentals of how electricity is produced, traded, and valued in the NEM.

In this context, our project aims to deliver actionable, data-driven insights into the NEM's emissions trajectory, market structure, and bidding dynamics. By leveraging a combination of historical records, recent market data, and advanced analytics in Python, we systematically analyze key trends in carbon intensity, intra-daily emissions patterns, and the interplay of consumer behavior and regional generation resources. Special attention is paid to the evolution of bidding strategies by different generation technologies such as solar, OCGT, and black coal over the crucial period from 2019 to 2025.

Our analysis goes beyond descriptive trends to interrogate the strategic and investment implications of these shifts. By unpacking changes in bidding behavior, price volatility, and market share, we highlight how the growing role of renewables is fundamentally altering risk-return profiles and revenue streams in the market. The findings are synthesized into clear, practical recommendations for investors, policymakers, and industry stakeholders seeking to navigate and capitalize on the NEM's transition to a low-carbon future.

This report is the product of collaborative effort, with each team member focusing on a key dimension of the market transition from regional emissions drivers to the granular details of bid stack evolution and scenario modeling. Together, our work provides a comprehensive and strategic perspective on the opportunities and risks at the heart of Australia's renewable energy revolution.

1. Carbon Emission Intensity of the NEM in Recent Years

The carbon emission intensity in the National Electricity Market (NEM) has significantly decreased over the last decade. Carbon intensity measures the amount of carbon dioxide (CO_2) emitted per unit of electricity generated. A reduction in this intensity reflects the sector's transition from fossil fuel-based energy generation towards renewable energy sources, such as wind, solar, and hydroelectric power.

- **Average CO_2 Intensity (2011-2024)**: The NEM's carbon intensity decreased from an average of 1.2 in 2011 to approximately 0.75 in 2024, reflecting a substantial shift towards cleaner energy sources.

- **Average Carbon Intensity in 2012**: In 2012, the NEM's carbon intensity was recorded at 1.21, which declined steadily through the years, reaching 0.75 in 2023 (as seen in Figure

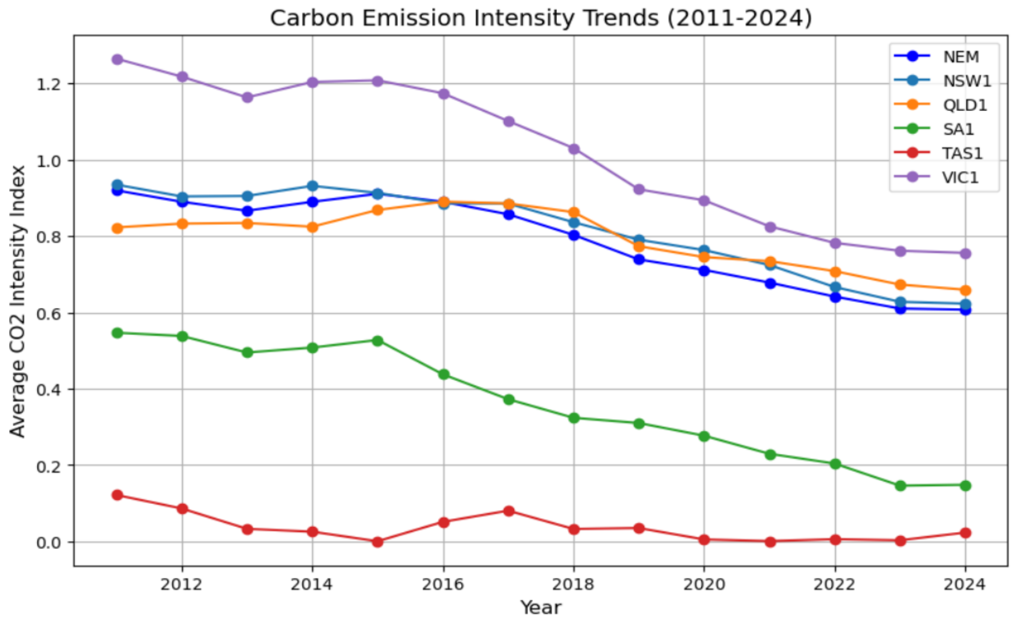


Figure 1: Carbon Emission Intensity Trends (2011-2024)

This graph shows the trend of carbon emission intensity for NEM as well as for each of its regional markets (NSW1, QLD1, SA1, TAS1, and VIC1) from 2011 to 2024.

2. Trend for the Entire NEM and Across the Five Regional Markets

The NEM has seen a notable decline in carbon emission intensity, but the extent of the reduction varies across regions. The trends are driven by a combination of regional renewable energy adoption, the phasing out of coal-fired power plants, and the overall grid decarbonization efforts.

NEM Trend

The NEM's average CO_2 intensity index decreased from approximately 1.2 in 2011 to around 0.75 in 2024. The national reduction can largely be attributed to the increased share of renewables in the energy mix, including the growth of solar, wind, and hydroelectric energy.

- NEM: The overall carbon intensity has been consistently declining. This trend reflects Australia's increasing reliance on renewable energy sources.

Regional Breakdown

Each region's performance has varied:

- **NSW1**: New South Wales has seen a more gradual reduction due to continued coal dependency. From around 0.89 in 2012 to approximately 0.75 in 2024, the carbon intensity decreased slowly due to the state's reliance on coal-fired power plants, despite an increasing share of renewable energy in the mix.

- **QLD1**: Queensland's rate of change is moderate, indicating a slower transition towards renewable sources despite large solar investments. The carbon intensity decreased from around 0.89 in 2012 to approximately 0.73 in 2024, due to increased solar adoption but continued reliance on fossil fuels.

- **SA1**: South Australia has seen the steepest reduction in carbon intensity, from around 0.55 in 2012 to approximately 0.12 in 2024. This is largely due to its widespread adoption of wind energy, which has substantially reduced the region's emissions per unit of electricity. South Australia's progress is a testament to how a strong focus on renewable energy, particularly wind, can significantly decarbonize a regional grid.

- **TAS1**: Tasmania, with its near-total reliance on hydropower, consistently maintained the lowest carbon intensity throughout the period. Tasmania's carbon intensity remained at a remarkably low level of around 0.20 throughout the years, as hydroelectric power provides clean, renewable energy with virtually no emissions.

- **VIC1**: Victoria's carbon intensity has reduced, but its use of brown coal has limited the pace of change. The carbon intensity decreased from approximately 0.92 in 2012 to around 0.7 in 2024, as the state is still highly dependent on coal. However, recent investments in wind and solar have begun to make a difference, and the region is on track to reduce its emissions further.

PUBLIC CONTRACTYEAR	avg_co2_intensity	co2_intensity_pct_change
2012	0.889476	-3.253808
2013	0.866099	-2.628137
2014	0.889396	2.689873
2015	0.910384	2.359762
2016	0.889573	-2.285960
2017	0.856775	-3.686912
2018	0.802937	-6.283817
2019	0.738480	-8.027636
2020	0.711183	-3.696409
2021	0.677978	-4.669012
2022	0.641346	-5.403116
2023	0.610011	-4.885751
2024	0.607098	-0.477653

Figure 2: Annual Carbon Emission Changes (2012-2024)

This graph illustrates the percentage change in carbon intensity for each year from 2012 to 2024. The data shows sharp reductions starting in 2019, with the greatest reductions occurring in 2022 and 2023.

- The sharpest reduction in CO2 intensity was in 2020 (-3.7%), followed by a steady decrease through 2024.
- These changes are a direct reflection of increased renewable energy contributions and the ongoing closure of coal plants in certain regions, particularly in South Australia and Tasmania.

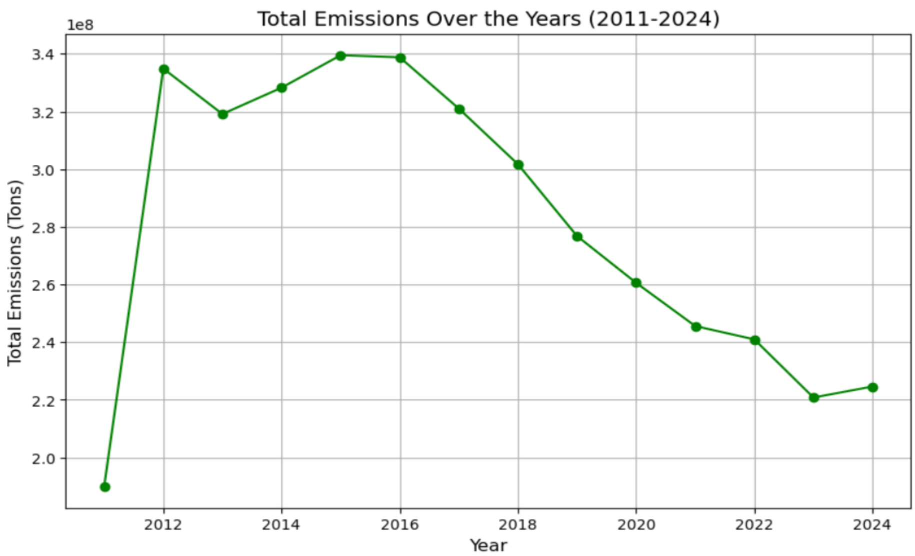


Figure 3: Total Emissions Over the Years (2011-2024)

This figure tracks the total emissions in tons over the years, revealing a sharp drop in total emissions since 2012.

- In 2012, emissions peaked at over 3.2 million tons, primarily due to the use of fossil fuels like coal. By 2024, total emissions had decreased to approximately 2.3 million tons, representing a significant decrease as renewable energy sources began to dominate the grid.

3. Energy Sent Out vs CO2 Intensity

Figure 4 depicts the relationship between the total energy sent out (in MWh) and the corresponding CO2 intensity (in gCO2/kWh). This scatter plot shows how the CO2 intensity varies with the amount of energy produced.

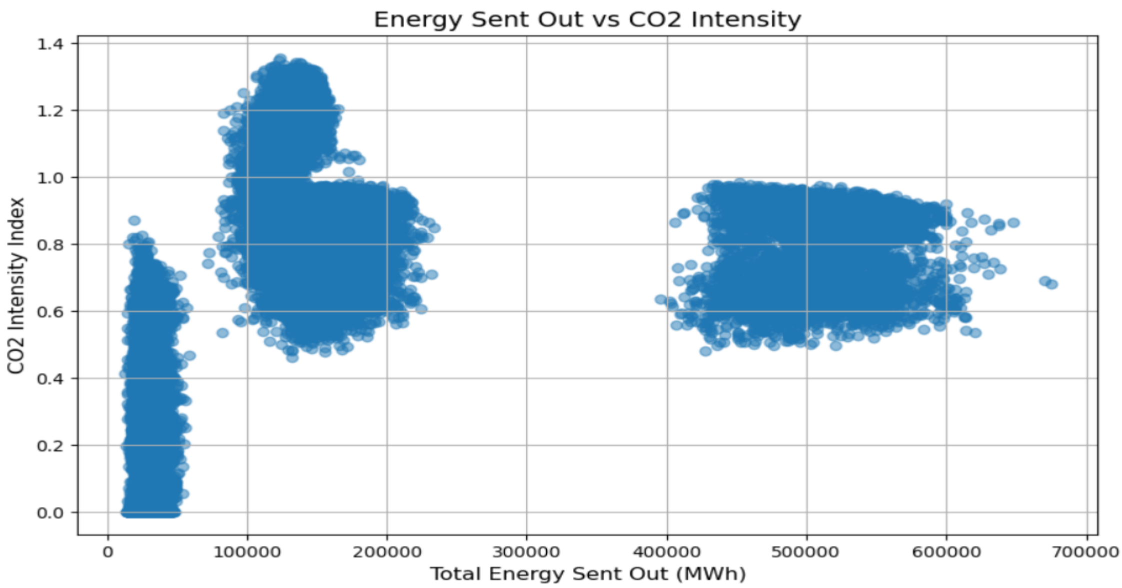


Figure 4: Energy Sent Out vs CO2 Intensity

Energy sent out typically has lower CO2 intensity as renewable generation increases. However, the scatter plot reveals that periods of high energy output still correspond to high CO2 intensity, especially during times of low renewable output and high fossil fuel generation.

This indicates that while more energy is being sent out, a large portion of it is still produced from higher-carbon sources like coal and gas during peak periods.

4. Seasonal Trends of Carbon Emission Intensity

The seasonal variation in carbon intensity reflects how energy consumption changes throughout the year. During peak demand periods (For Example - summer months), fossil fuel power plants are often relied upon more heavily to meet the energy demand, increasing carbon intensity.

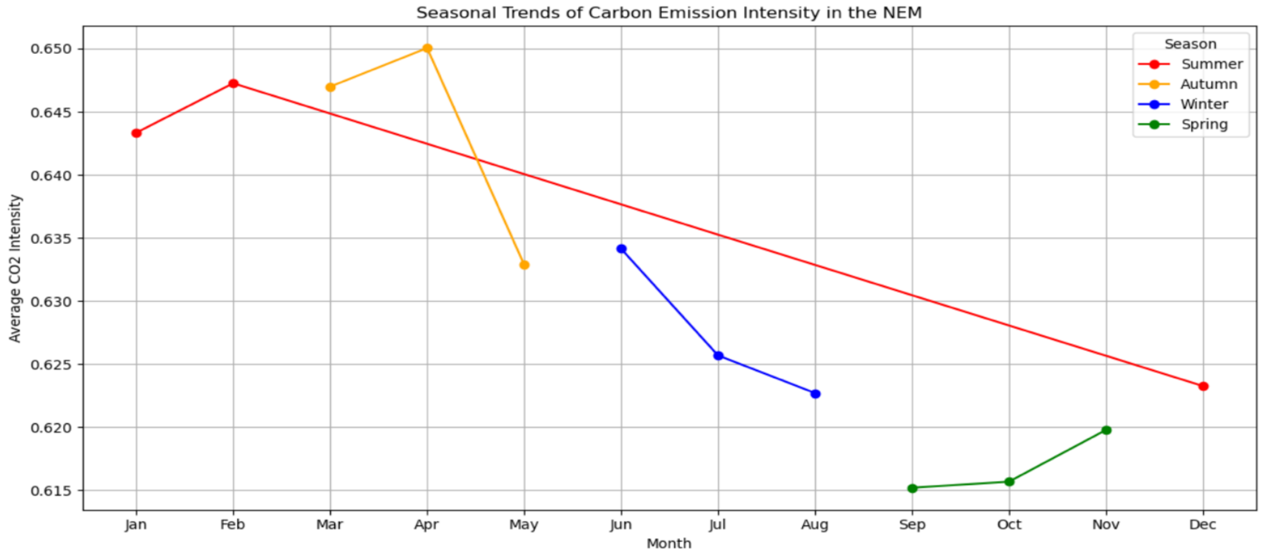


Figure 5: Seasonal Trends of Carbon Emission Intensity in the NEM

Figure 5 shows seasonal trends of carbon intensity from 2011 to 2024.

- Summer (Red): Shows the highest carbon intensity, as energy demand for cooling spikes during the hotter months.
- Winter (Blue): Has relatively lower emissions compared to summer, reflecting lower energy demand and a higher share of renewables in the energy mix.
- Spring (Green) and Autumn (Yellow): These months typically show a moderate carbon intensity, as energy demand for heating and cooling is balanced.

5. Main Reasons for Changes in Carbon Emission Intensity

Several interrelated factors have contributed to the significant reduction in carbon emission intensity within the National Electricity Market (NEM) over recent years. These changes reflect a broad shift in energy production, consumption patterns, and technological advancements, all of which have worked together to reduce the environmental footprint of the Australian electricity sector.

Shift Toward Renewable Energy Sources

The most significant factor contributing to the decline in carbon emission intensity in the NEM is the rapid growth of renewable energy sources, including wind, solar, and hydroelectric power. This transition has significantly reduced the reliance on fossil fuels such as coal and natural gas, which were once the primary sources of electricity generation in Australia.

Over the years, the renewable energy share in the grid has steadily increased, particularly in regions like South Australia and Tasmania. South Australia's embrace of wind power has been particularly noteworthy, leading to a dramatic reduction in its carbon intensity. Tasmania, with its almost exclusive reliance on hydropower, has been able to maintain near zero carbon emissions, making it a model of clean energy production. Other regions have also seen improvements, though to varying extents depending on their energy mix and infrastructure.

The increasing capacity of solar energy has also played a crucial role, particularly in Queensland and New South Wales. Although Queensland still faces challenges in reducing carbon intensity due to its continued reliance on coal, solar energy adoption has nonetheless provided a significant contribution to the overall reduction in emissions.

Government Policies and Renewable Energy Targets

Government policies have been instrumental in accelerating the shift toward cleaner energy. The Renewable Energy Target (RET), for example, has set ambitious goals for renewable energy generation, driving investments in wind, solar, and other clean technologies. Both federal and state governments have introduced subsidies and incentives for renewable energy projects, which have significantly reduced the upfront costs of installing and operating renewable energy systems.

Furthermore, specific regional policies, such as the South Australian government's strong focus on wind energy, have fostered a more rapid decarbonization of the energy grid. These policies, combined with the federal commitment to reduce greenhouse gas emissions, have helped create a favorable environment for renewable energy investments, which have been critical in decreasing the carbon intensity of electricity generation.

Technological Advancements

The evolution of renewable energy technologies has been another key factor. Advances in energy storage, such as battery storage systems, have made it more feasible to integrate renewable energy into the grid by allowing excess energy generated during periods of high renewable output (such as sunny or windy days) to be stored and used later. This has helped address one of the main challenges with renewable energy intermittency and has enabled more consistent and reliable renewable energy supply, reducing the reliance on fossil fuel-based backup generation.

Furthermore, improvements in the efficiency and cost-effectiveness of solar panels and wind turbines have allowed for larger-scale renewable energy projects to be developed more economically. The continuous innovation in renewable energy technologies has made them increasingly competitive with traditional fossil fuel generation, ensuring that the transition to cleaner energy is both environmentally and economically viable.

Phase-Out of Coal-Fired Power Plants

The gradual closure of coal fired power plants has also played a crucial role in decreasing the carbon intensity of the NEM. As these high emission plants have been phased out, the gap has been filled by cleaner sources of energy, such as solar, wind, and hydroelectric power. This process has been particularly evident in regions like South Australia, where the closure of coal plants has allowed for a greater share of renewable energy to enter the grid.

Despite the challenges posed by coal's continued presence in some regions, such as New South Wales and Victoria, the ongoing closure of these plants in favor of renewables will likely continue to drive down carbon emissions in the future. As more coal plants are decommissioned, the grid will rely more heavily on cleaner sources, leading to a further reduction in carbon intensity.

Energy Consumption Patterns

Energy consumption patterns also play a role in shaping the overall carbon intensity of the NEM. During peak demand periods, particularly in summer, fossil fuel plants are often used to meet increased electricity consumption, especially for air conditioning and cooling. This increases the carbon intensity, as fossil fuel generation typically emits higher levels of CO2 compared to renewable sources.

However, this seasonal variation in demand has been somewhat mitigated by the increasing adoption of renewable energy, which can help meet the energy demands even during periods of peak consumption. For instance, solar energy production peaks during the summer months when energy consumption is high, helping to reduce the need for fossil fuel-based power generation.

In contrast, during the winter months, energy consumption is generally lower, and the energy mix tends to shift towards a higher share of renewables, leading to a lower overall carbon intensity. These seasonal trends are important to consider when evaluating carbon emission intensity, as they demonstrate how variations in demand can influence the overall emissions profile of the grid.

6. Intra-Daily Carbon Emission Patterns Across Regions

Understanding how carbon emission intensity varies throughout the day is essential for effective demand management, renewable energy planning, and emission reduction strategies. This section examines intra daily emission patterns across New South Wales, Victoria, Queensland, South Australia, and Tasmania using time series data averaged from 2019 to 2025.

6.1 Intra-Daily Emission Line Plot: Regional Curves

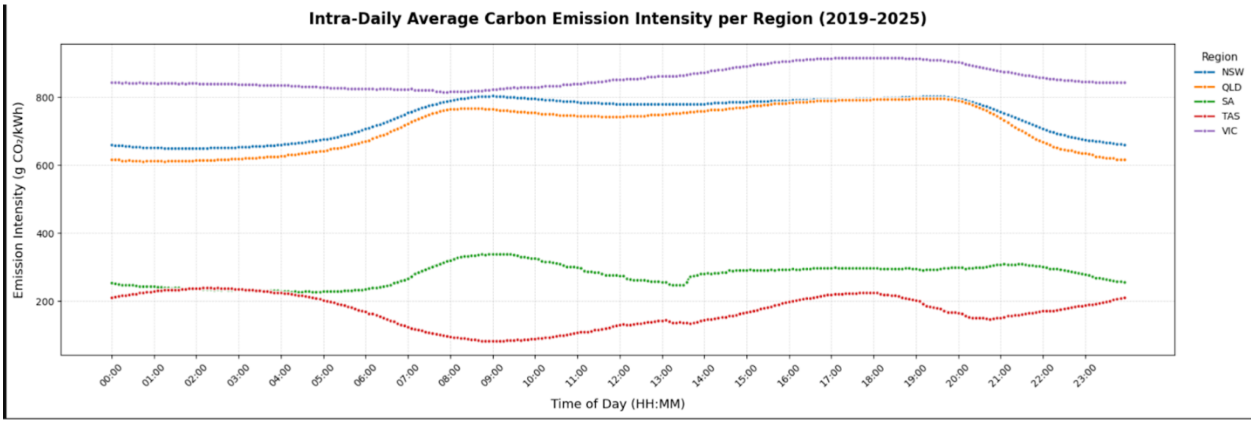


Figure 6.1 Intra-Daily Carbon Emission Intensity per Region (2019-2025)

Figure 6.1 reveals distinct daily rhythms across regions. New South Wales, Victoria, and Queensland follow a double peak pattern, with sharp rises in the morning between 6 and 9 AM and another increase in the evening from 5 to 8 PM. These peaks align with typical household and industrial activity. Tasmania displays a clear U-shaped curve, with a significant dip in emissions during midday hours from 9 AM to 3 PM, likely due to strong solar or hydroelectric input.

Overall, fossil fuel dominant regions maintain high and stable emission levels throughout the day, while regions with stronger renewable integration experience lower and more dynamic emissions, especially during daylight hours.

6.2 Heatmap Analysis: Hourly Emission Intensity by Region

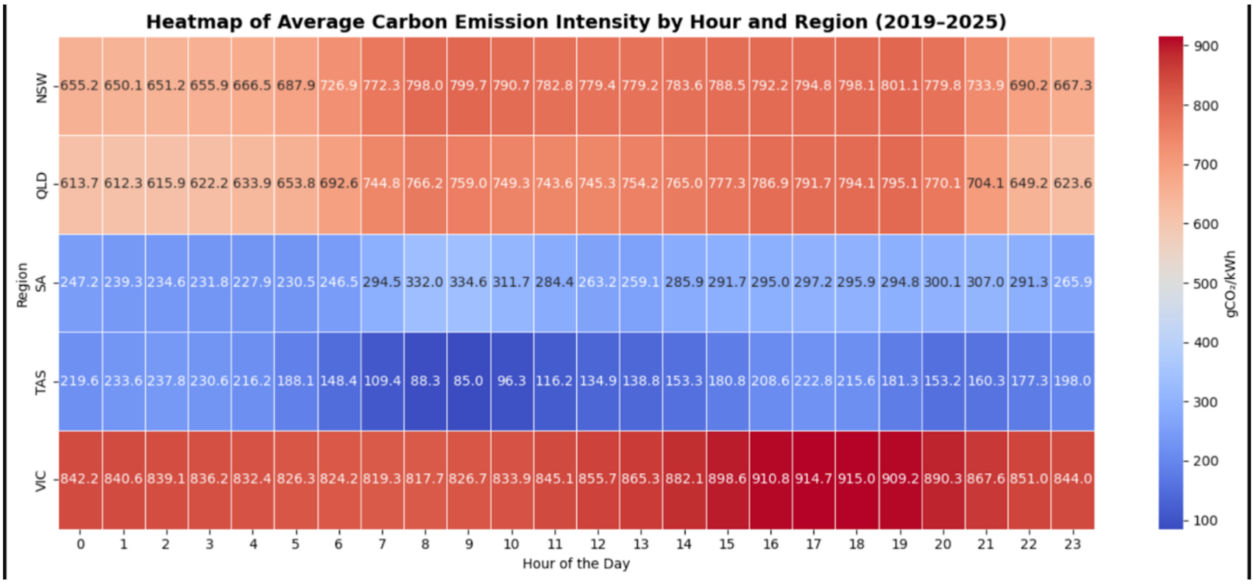


Figure 6.2.1 Heatmap of Average Carbon Emission Intensity by Hour and Region (2019-2025)

Figure 6.2.1 highlights the daily emission peaks and lows through color variation. Victoria shows the highest and most consistent emissions throughout the day, peaking above 900 grams of carbon dioxide per kilowatt hour between 6 and 8 PM. New South Wales and Queensland follow a similar pattern, with clear peaks around 8 AM and again in the evening. In contrast, Tasmania records its lowest emissions from 9 AM to 12 PM, dropping as low as 85 grams. South Australia shows moderate and steady emissions, with slight fluctuations due to changing wind output.

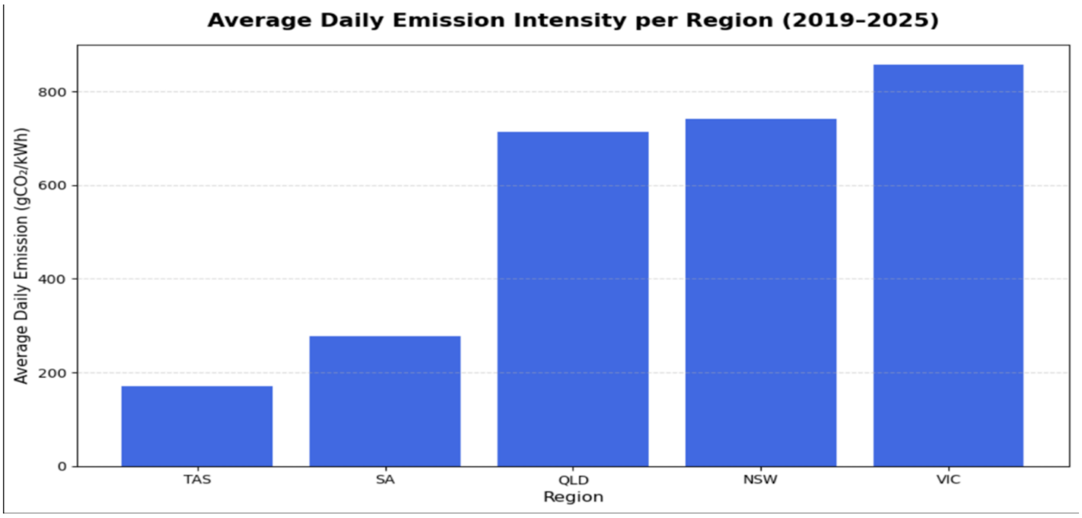


Figure 6.2.2 Average Daily Emission Intensity per Region

Figure 6.2.2 shows a clear divide between states with high and low dependence on fossil fuels. South Australia and Tasmania report much lower average daily emissions. This is consistent with their stronger use of renewable energy, such as wind and hydro, and reflects the midday emission dips observed in previous graphs.

This comparison reinforces that a region's long term emission levels are closely linked to its energy mix. While the intra daily charts show when emissions peak, this daily average view confirms which regions are the most carbon intensive overall.

6.3 Total Emission Contribution by Region

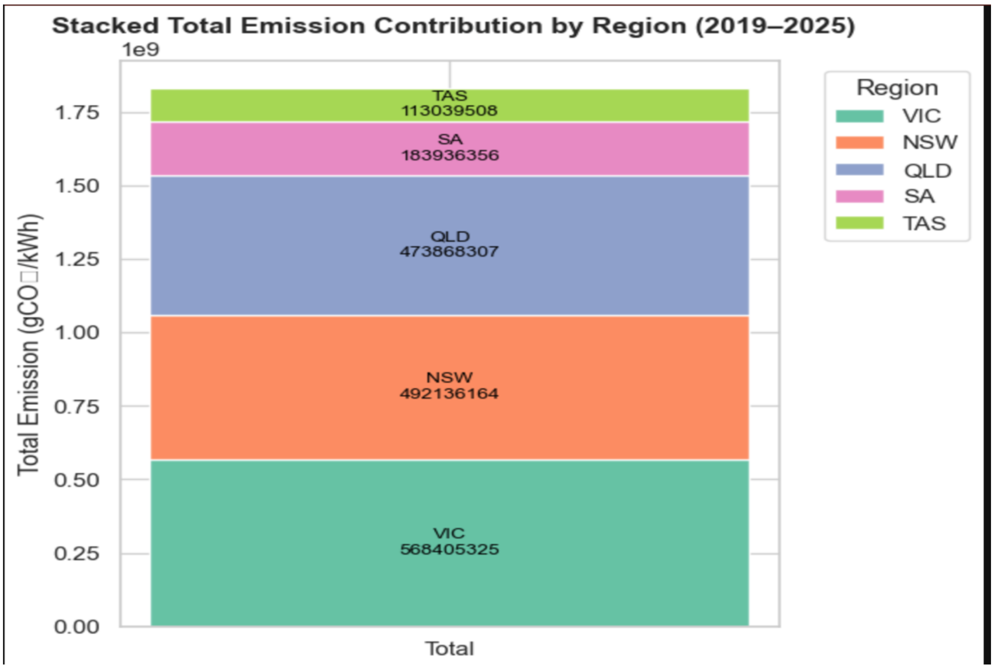


Figure 6.3 Total Emission Contribution by Region

To complete the regional comparison, this stacked bar chart shows the total carbon emissions from each NEM region between 2019 and 2025. Victoria is the largest contributor, followed by New South Wales and Queensland. This reflects their higher daily emission levels and larger electricity demand, as seen earlier.

This chart helps link short-term emission patterns to long-term impact, highlighting which regions need urgent emission reduction efforts and which serve as models for clean energy adoption.

6.4 Cumulative Emission Contribution

To extend the previous time-based and average daily emission insights, this section evaluates the total cumulative carbon emission contribution by region across the 2019–2025 period. This shift in focus from time-interval trends to total burden highlights which regions have had the greatest overall environmental impact.

Figure 6.4.1 below clearly illustrates the absolute cumulative emission (in gCO_2/kWh) from each of the five NEM regions. Victoria leads with a substantial total of over 568 million gCO_2/kWh, followed closely by New South Wales (492 million) and Queensland (474 million). These three regions collectively account for most emissions during the period, reflecting their continued reliance on fossil fuel-based generation.

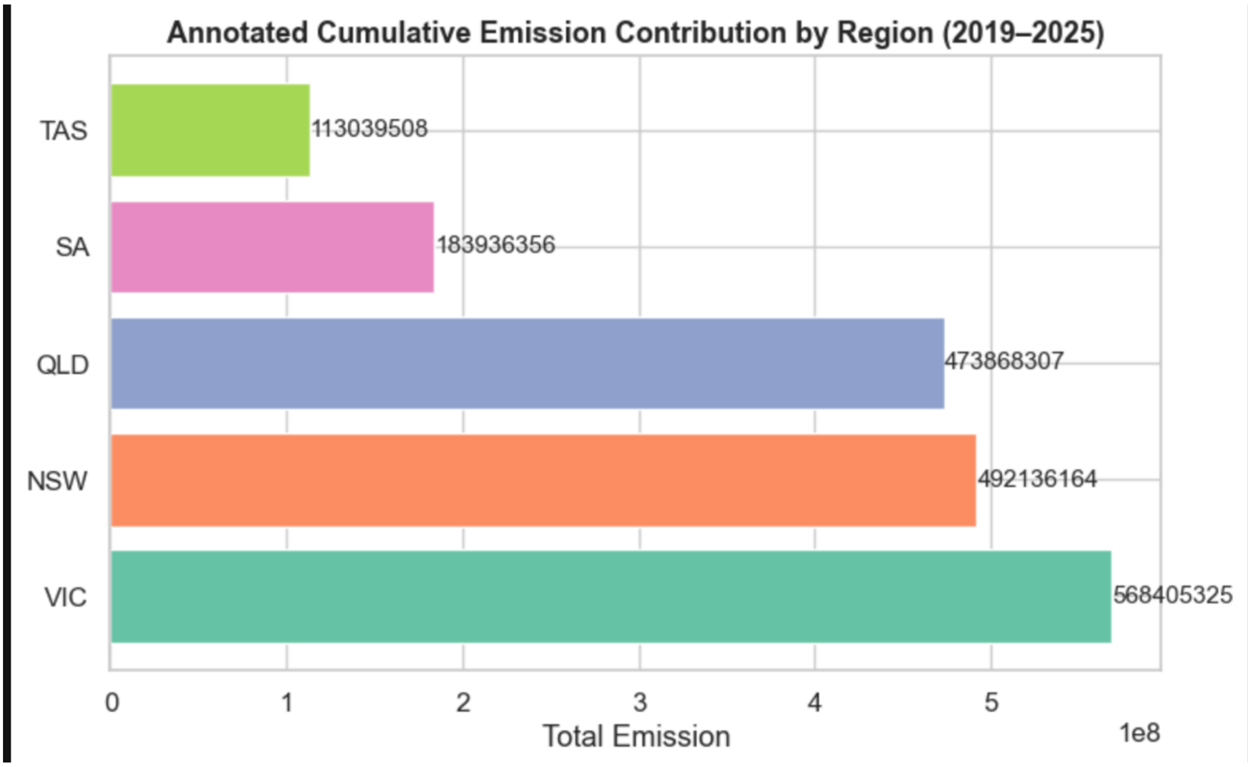


Figure 6.4.1 Cumulative Emission Contribution by Region

Meanwhile, South Australia and Tasmania register significantly lower cumulative emissions approximately 184 million and 113 million gCO_2/kWh, respectively. This is consistent with their cleaner intra-daily and average daily emission profiles discussed earlier, and it further underscores the benefits of a renewable-heavy energy mix.

To better visualize proportional contributions, Figure 6.4.2 below offers a percentage breakdown of the same data. VIC emerges as the largest emitter, accounting for 31% of total emissions in the NEM over the analysis period. NSW and QLD follow with 26.9% and 25.9%, while SA and TAS contribute just 10% and 6.2%, respectively.

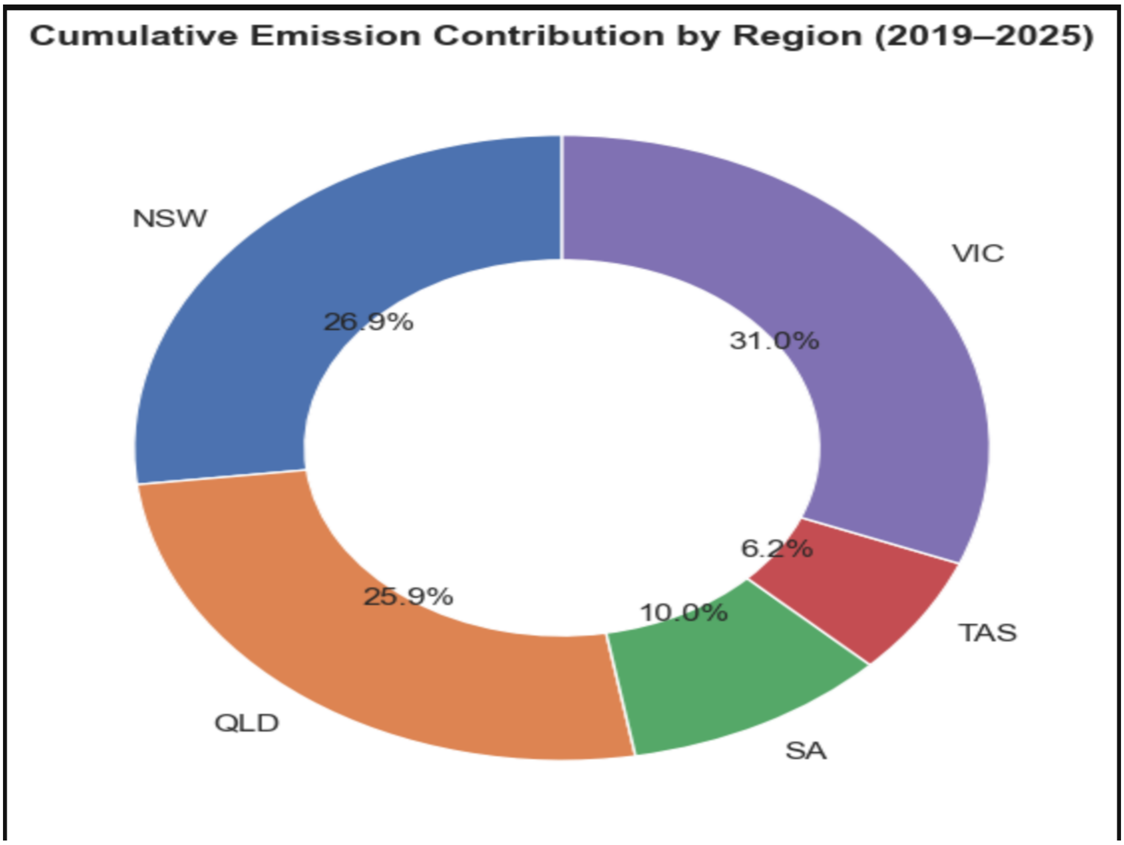


Figure 6.4.2 Percentage of Cumulative Emission Contribution by Region

This cumulative perspective strengthens the earlier intra-daily findings by demonstrating how sustained high-emission patterns.

6.5 Year-on-Year Emission Intensity Trends

To understand the temporal dynamics of emission intensity, this section investigates how carbon emissions have changed on a yearly basis for each NEM region between 2019 and 2025. Figure 6.5 below illustrates the percentage change in average annual carbon emission intensity, offering insight into the direction and volatility of regional decarbonization efforts.

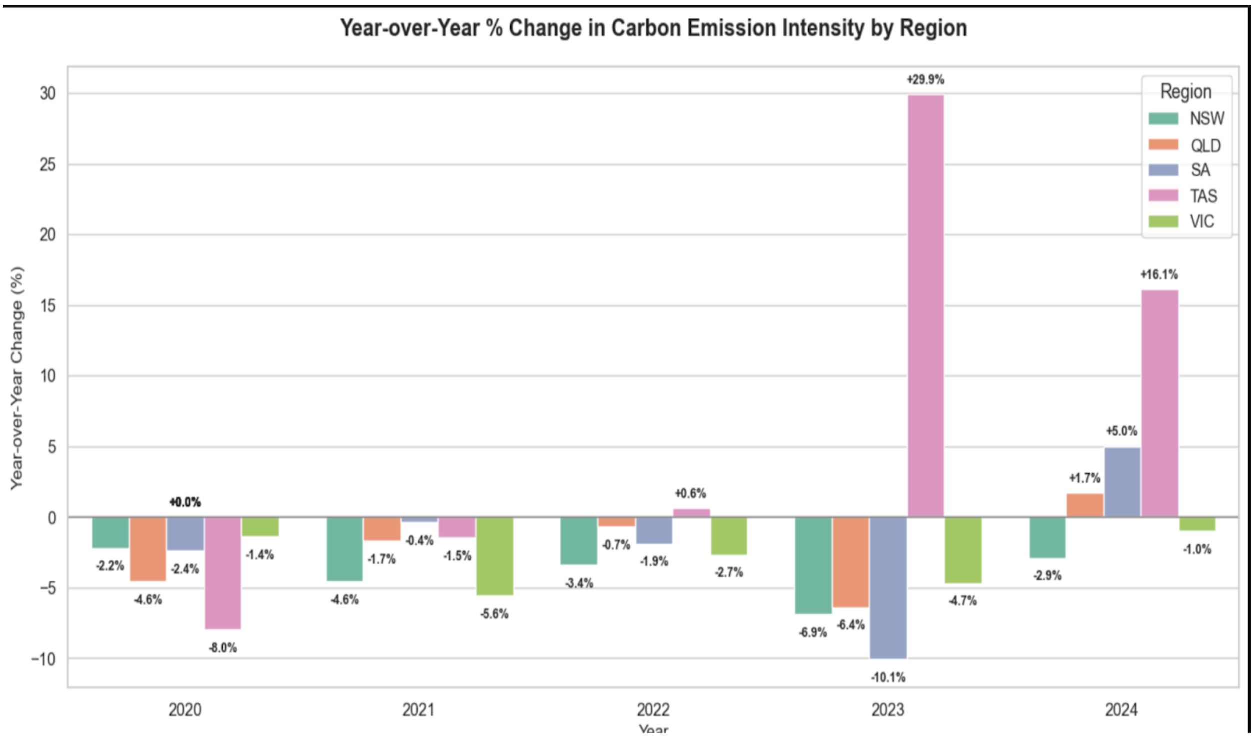


Figure 6.5 Year-over-Year Percentage Change in Carbon Emission Intensity by Region

From 2020 to 2022, most regions recorded steady year on year declines in carbon emission intensity, showing gradual progress in reducing grid emissions. Victoria and Tasmania, in particular, saw consistent improvements, likely due to ongoing investment in renewable energy.

However, 2023 marked a significant exception. While Victoria, South Australia, New South Wales, and Queensland all recorded further declines, including a 10.1 percent drop in South Australia, Tasmania showed a sharp reversal. Its emission intensity increased by 29.9 percent, which may be due to lower hydroelectric output caused by dry weather or reduced water inflows.

In 2024, several regions experienced a partial rebound. South Australia, New South Wales, and Queensland all recorded moderate increases in emissions, while Victoria returned to a slight decline. Tasmania again showed a large increase of 16.1 percent, which supports the idea that its emissions are affected by weather related changes in hydro supply.

Overall, Figure 6.5 shows that regions using more renewable energy such as Tasmania and South Australia tend to have more variation in emissions. Regions that rely more on fossil fuels show more stable but slower changes. These results suggest that while renewables lower average emissions, they also require flexible planning to deal with changes in supply.

7. Seasonal Trends in Emission Intensity

Seasonal carbon emission patterns offer a valuable lens into how energy systems perform under different climate conditions, load profiles, and renewable availability throughout the year. In this section, we combine two key visualizations to understand both regional intensity fluctuations and seasonal emission share contributions across the NEM.

We selected 2024 as the representative year because the emission trends observed during this period closely align with those of surrounding years. This consistency allows us to effectively illustrate the broader seasonal patterns without the need to include multiple overlapping graphs. By focusing on a single, recent, and complete year, the analysis remains both streamlined and informative while preserving the integrity of the overall trend.

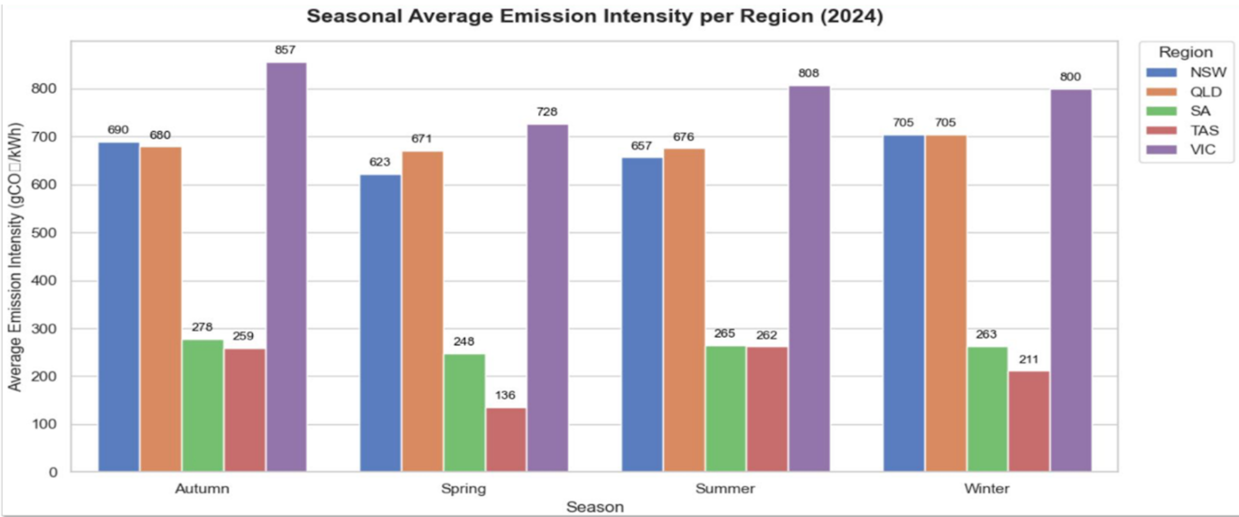


Figure 7.4.1 Seasonal Average Emission Intensity per Region (2024)

Figure 7.4.1 presents the average emission intensity (gCO_2/kWh) by season for each of the five regions in 2024. Victoria consistently records the highest emission intensity across all seasons, peaking in spring at 857 gCO_2/kWh. This indicates persistent fossil-fuel reliance with minimal seasonal variation in the energy mix.

New South Wales and Queensland also show elevated but steadier emissions across the year. Notably, spring is the cleanest quarter for New South Wales, while Queensland remains mostly flat across seasons.

In contrast, South Australia and Tasmania stand out for their significantly lower seasonal averages. South Australia's emission intensity remains around 260–278 gCO_2/kWh, reflecting a relatively stable renewable contribution from wind. Meanwhile, Tasmania achieves a remarkable low in spring (136 gCO_2/kWh), pointing to the seasonal strength of hydroelectricity. These seasonal variances underscore the dynamic role renewables play in modulating carbon intensity.

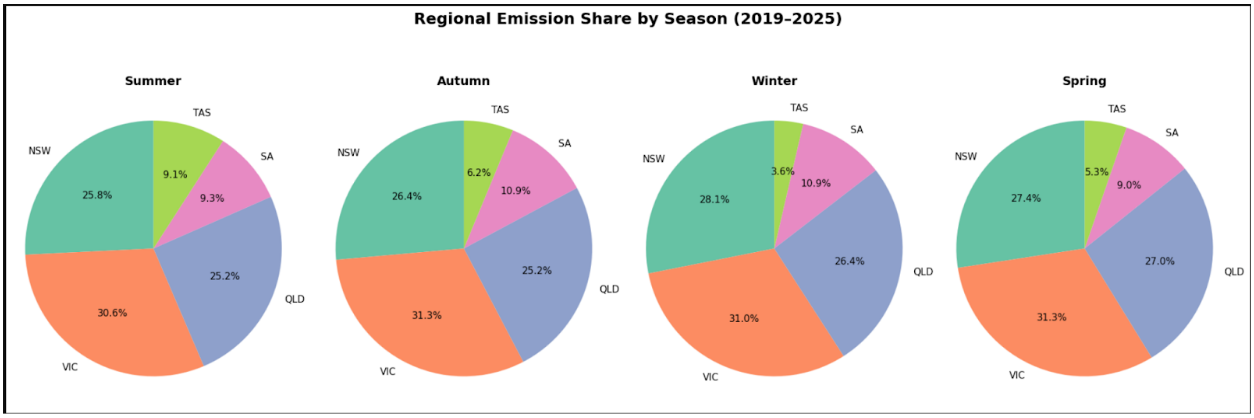


Figure 7.4.2 Regional Emission Share by Season

Figure 7.4.2 provides further depth by breaking down each region's proportional contribution to total emissions across seasons. Victoria contributes the largest share in every season, peaking at 31.3% in both spring and autumn, reinforcing its role as the top emitter in cumulative terms. New South Wales and Queensland follow closely, contributing 25–28% each, while SA and TAS remain minor contributors, rarely exceeding 11%.

Interestingly, Tasmania's share drops to as low as 3.6% in winter, reflecting reduced hydro availability or increased demand during colder months. South Australia's share remains stable across seasons, indicating wind's relatively consistent output.

8. Emission Impacts of Renewables

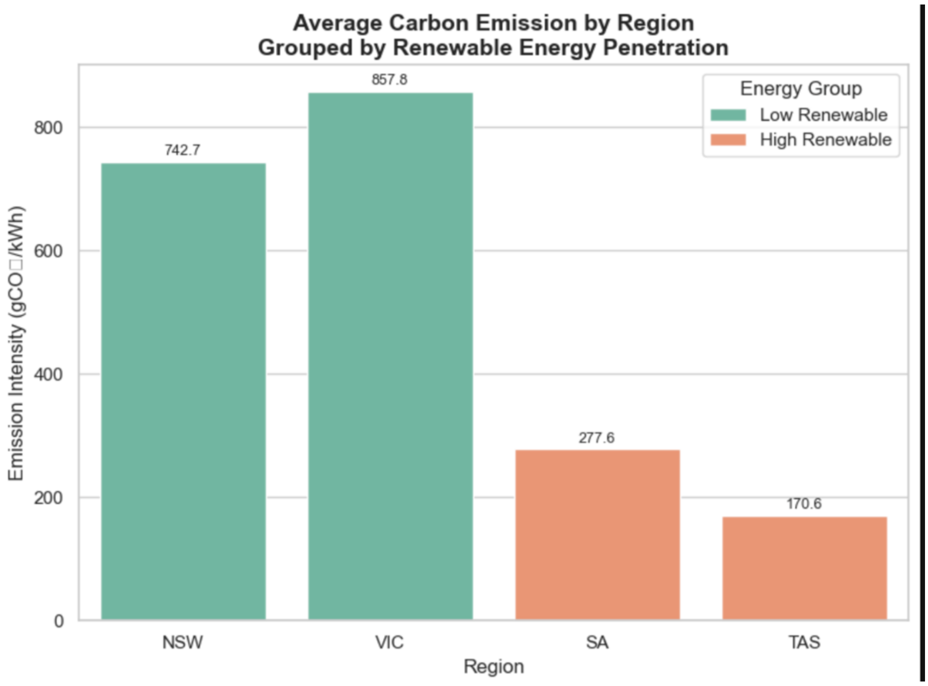


Figure 8.1 Average Carbon Emission by Renewable Energy Penetration

Figure 8.1 groups four regions: New South Wales, Victoria, South Australia, and Tasmania into two categories based on their level of renewable energy use. The chart shows a clear difference in average carbon emission intensity, measured in grams of carbon dioxide per kilowatt hour, between regions with low and high shares of renewable electricity from 2019 to 2025.

Victoria has the highest average carbon intensity at 857.8 grams, followed by New South Wales at 742.7 grams. Both regions still rely heavily on fossil fuel sources, especially coal, which leads to higher emission levels. In contrast, South Australia and Tasmania have much lower average emissions — 277.6 and 170.6 grams, respectively due to the use of wind power in South Australia and hydro power in Tasmania.

This comparison shows that regions with more renewable energy tend to have lower carbon emissions. It also reflects real progress toward national and state climate goals. The chart highlights the value of investing in clean energy and suggests that regions with lower renewable use should be prioritised for energy policy support and infrastructure upgrades.

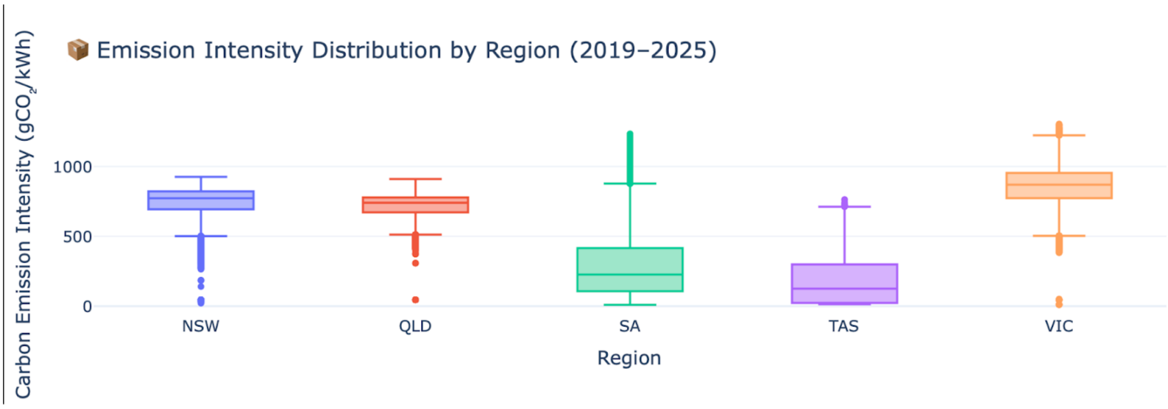


Figure 8.2 Emission Intensity Distribution

Figure 8.2 uses boxplots to provide a deeper understanding of how carbon emissions are distributed across regions. States such as Victoria and Queensland, which rely more on fossil fuels, display both high average emission levels and wider interquartile ranges, along with more extreme values. This pattern suggests a combination of consistently high emissions and exposure to sharp increases, likely caused by demand spikes, reduced renewable output, or dependence on fossil fuel backup.

In contrast, Tasmania and South Australia show lower median emissions and narrower spreads. Tasmania, in particular, has a compressed interquartile range concentrated near the lower end, with few extreme values. This indicates strong and consistent clean energy generation, mainly from hydroelectric sources. South Australia, which uses more wind power, shows slightly greater variability but still maintains a relatively low baseline for emissions.

9. South Australia as a Green Energy Benchmark

South Australia (SA) has emerged as a standout performer in the National Electricity Market (NEM) in terms of renewable energy integration and carbon emission intensity management. Figure 9 illustrates SA's hourly average carbon emission intensity from 2019 to 2025, offering an in-depth view of its intraday behavior across a day.

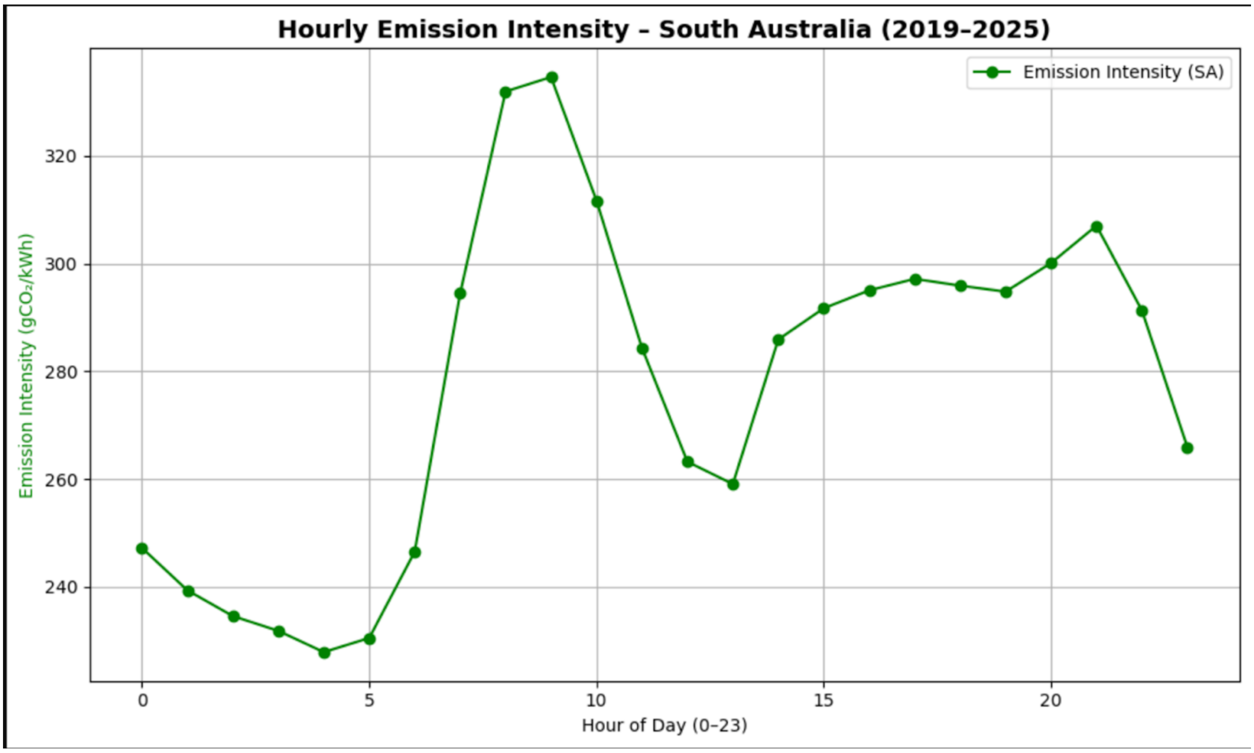


Figure 9 Hourly Emission Intensity (South Australia)

The daily emission curve in South Australia shows a unique pattern compared to the flatter and consistently high emission levels seen in states that rely more on fossil fuels. Emissions begin at a low level just after midnight and continue to fall, reaching the lowest point around 5 to 6 AM. This reflects reduced overnight demand and possible contributions from wind energy.

From 6 AM, emissions rise quickly, reaching a peak between 8 and 9 AM as households and businesses start their day. This morning increase likely occurs when energy demand goes beyond the available renewable supply, requiring extra power from fossil fuel sources.

Around midday, between 12 and 2 PM, emissions drop again from approximately 335 to 258 grams of carbon dioxide per kilowatt hour. This decrease aligns with stronger solar and wind generation during the middle of the day. The curve rises again in the evening from 5 to 9 PM, marking a second demand peak, and then gradually declines toward midnight.

The noticeable dips after the morning and around midday show how renewables help manage emissions when demand is high. Overall, the curve represents a cleaner and more adaptive energy mix, supported by South Australia's strong focus on wind energy, solar installations, and energy storage. Although short spikes in emissions still happen due to changing demand or weather, the overall pattern suggests a more sustainable electricity system compared to regions that depend on fossil fuels.

10. Forecasted Daily Carbon Emission Intensity for 2026: SA vs NSW

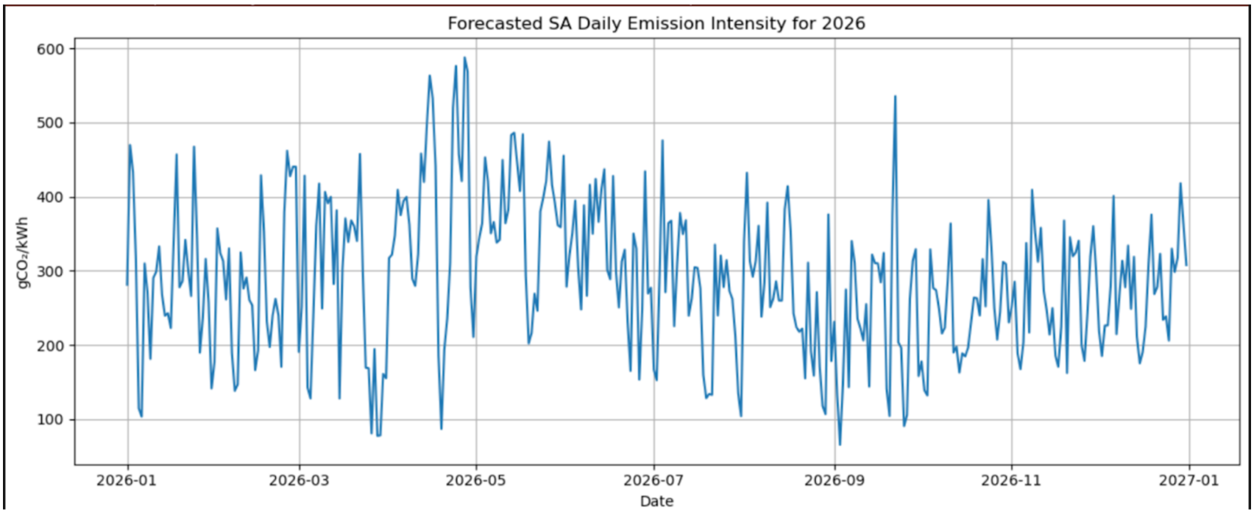


Figure 10.1 Forecasted South Australia Daily Emission Intensity for 2026

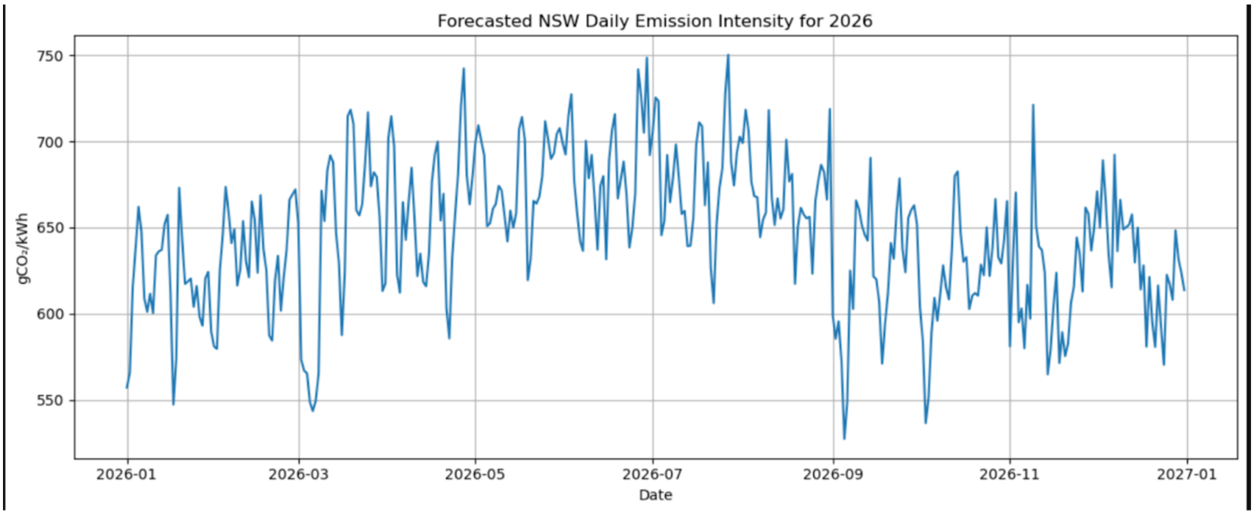


Figure 10.2 Forecasted South Australia Daily Emission Intensity for 2026

To explore the future of carbon emissions in the National Electricity Market, this section presents time series forecasts of daily emission intensity for the year 2026, focusing on two contrasting regions: South Australia and New South Wales. These forecasts are generated using a Random Forest Regressor model trained on historical data from 2019 to 2025. New South Wales was selected over Victoria to represent the high emission group due to Victoria's greater volatility, which made its patterns less suitable for accurate forecasting.

In the case of South Australia, the forecast shows daily emissions ranging from approximately 100 to 590 grams of carbon dioxide per kilowatt hour. The data reveals noticeable day to day variation, with the highest spikes occurring between April and June. Lower emission levels are more frequent during winter and late spring, reflecting the influence of wind power. As wind generation fluctuates, the region occasionally turns to fossil fuel backup, resulting in temporary peaks.

New South Wales, by contrast, shows a much more stable emission pattern, with most daily values falling between 550 and 750 grams. While there are minor fluctuations, the baseline remains consistently high throughout the year. This reflects the state's continued reliance on coal powered generation and a less adaptable grid. The smoother curve in New South Wales indicates fewer transitions between energy sources compared to the more flexible and renewable oriented profile seen in South Australia.

This comparison highlights a key structural difference between the two regions. South Australia, although more variable, maintains a lower average emission level due to its strong base of renewable generation. New South Wales, with its steady but elevated emissions, underscores the need for accelerated transition strategies such as storage deployment, diversified renewables, or gas displacement.

These forecasts offer valuable guidance for policymakers, enabling data-driven decisions on where to prioritise infrastructure investment, tailor emission targets, and support grid flexibility to ensure a balanced and sustainable energy future.

11. Emission Intensity by Day Type: Weekday vs Weekend Comparison

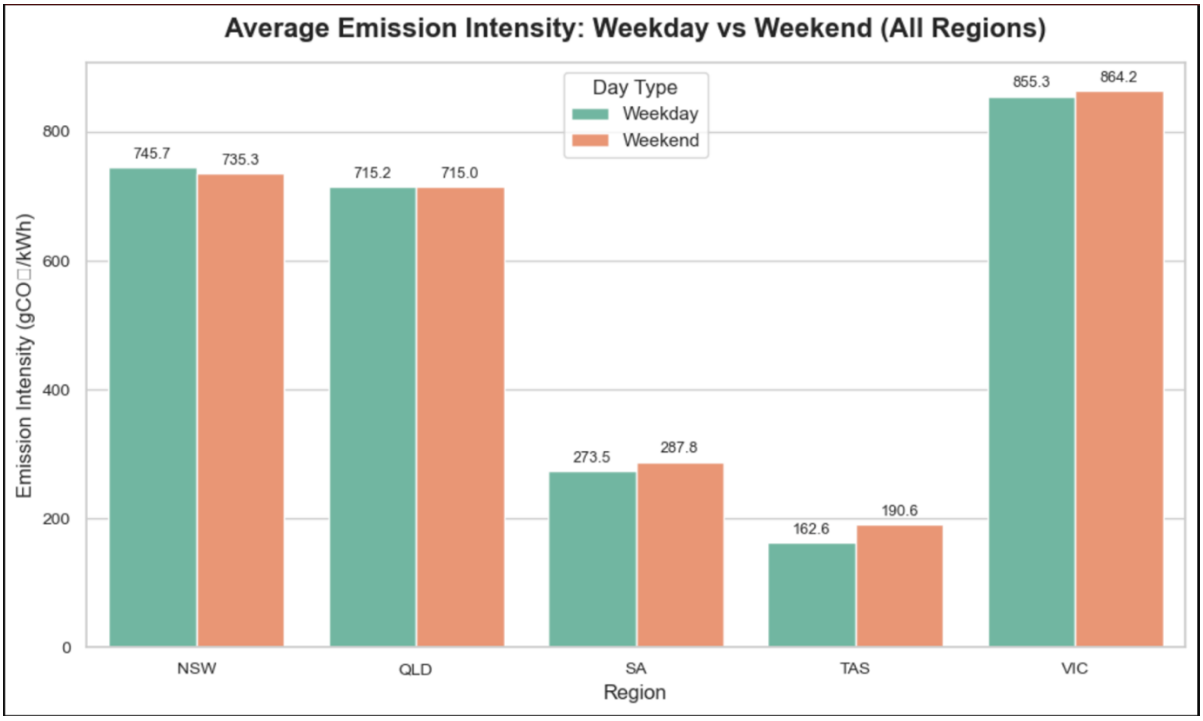


Figure 11 Average Emission Intensity: Weekday vs Weekend

By separating emissions by day type, the analysis highlights how changes in electricity demand driven by residential and industrial activity affect emission outcomes.

Figure 11 displays average emission intensity, measured in grams of carbon dioxide per kilowatt hour, for both weekday and weekend periods. As expected, Victoria and New South Wales record the highest emissions regardless of the day. In Victoria, emissions are slightly higher on weekends (864.2 compared to 855.3), possibly due to increased residential activity or reduced industrial offsets. New South Wales shows a minor drop on weekends (745.7 to 735.3), though the difference is relatively small.

Queensland maintains consistent emission levels across both weekdays and weekends, suggesting stable baseload generation and minimal variation in daily demand patterns.

In contrast, South Australia and Tasmania show more pronounced increases in emissions on weekends. South Australia rises from 273.5 to 287.8, and Tasmania from 162.6 to 190.6. These changes may be caused by lower renewable generation particularly wind in South Australia and hydro in Tasmania or shifts in weekend demand that require additional fossil fuel backup.

These trends reflect the complex relationship between daily human activity and carbon intensity. Regions dominated by fossil fuels tend to show stable emission patterns, while those with higher shares of renewable energy are more sensitive to demand changes and weather-related supply variability. This underscores the importance of demand-side planning and energy storage solutions to support reliable and clean electricity across all days of the week.

12. Time-of-Day Emission Patterns Across Regions

Understanding the variation in carbon emission intensity across different times of the day provides valuable insights for informing policy decisions and guiding consumer behavior. This section presents two visualizations that illustrate average emission profiles segmented by time of day such as night (12:00 AM to 6:00 AM), morning (6:00 AM to 12:00 PM), afternoon (12:00 PM to 6:00 PM), and evening (6:00 PM to 12:00 AM) across the five major regions of the National Electricity Market.

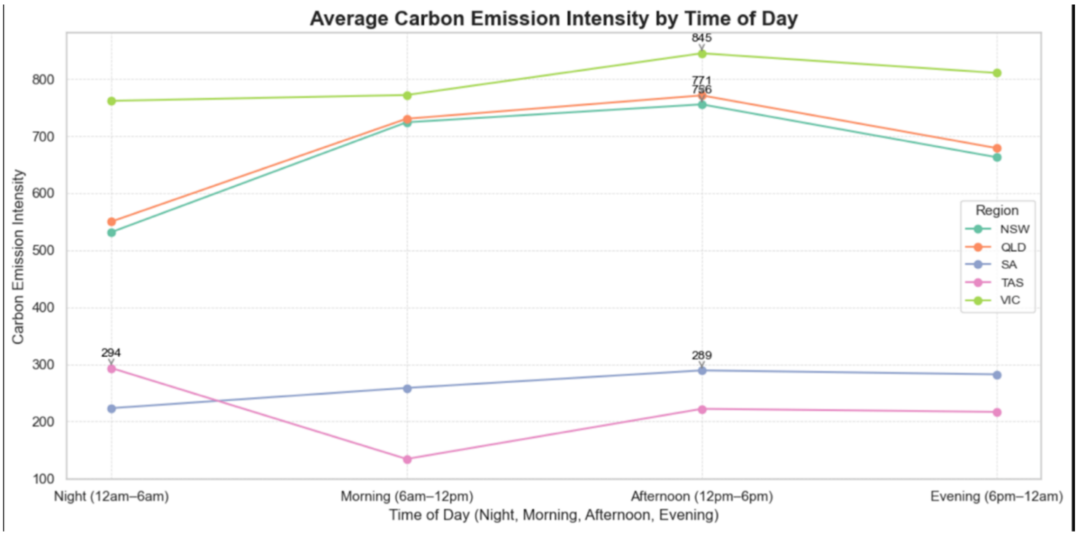


Figure 12.1 Average Carbon Emission Intensity by Time of Day

Figure 12.1 compares average carbon emission intensity across four time periods of the day for each region. Fossil fuel dependent states such as New South Wales, Queensland, and Victoria show clear peaks in the afternoon, with Victoria recording the highest level at 845 grams of carbon dioxide per kilowatt hour. Tasmania with the lowest emissions occurring in the morning at around 134 grams, which reflects strong hydroelectric generation during daylight hours. South Australia maintains a relatively steady trend, with a slight increase in the afternoon but overall stable emissions, indicating a balanced contribution from both wind and solar energy.

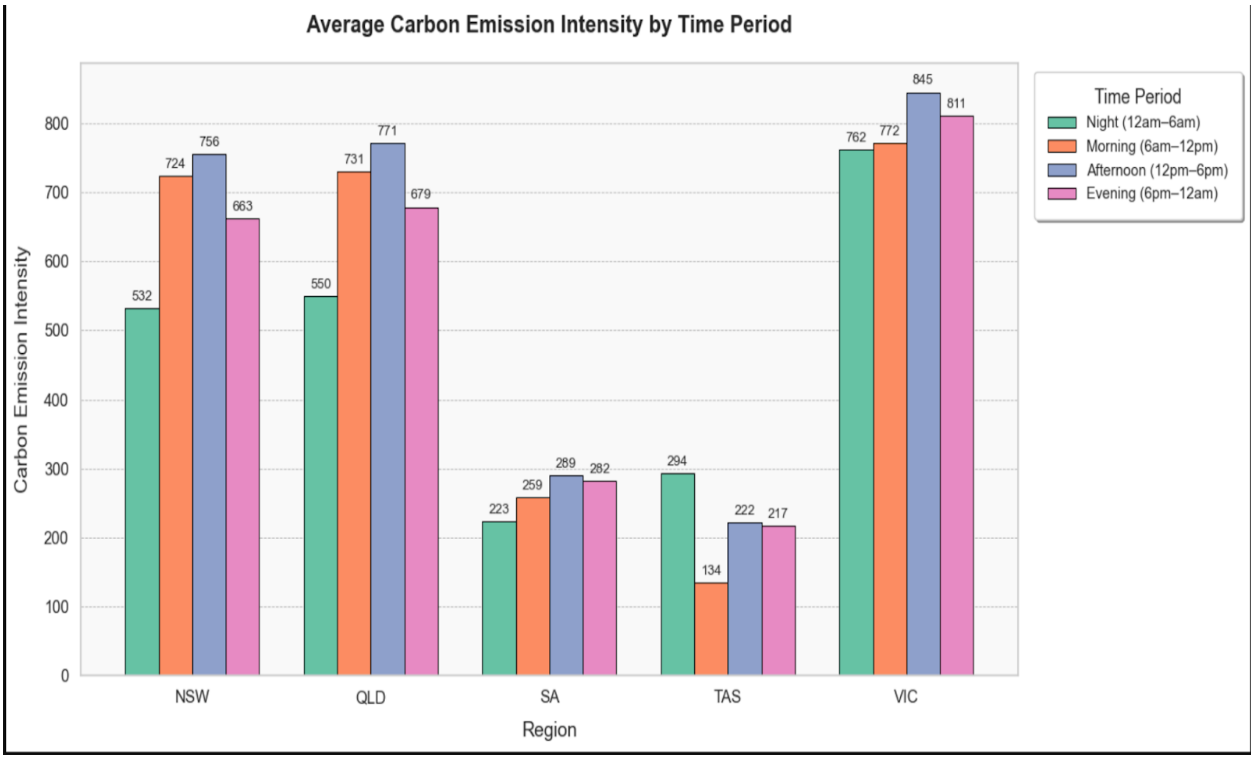


Figure 12.2 Average Carbon Emission Intensity by Time Period

Figure 12.2 supports the previous line graph by presenting the same emission data in a segmented, side by side format for each region. It highlights the significant daytime carbon burden in regions with greater fossil fuel use. In Victoria, emissions remain above 800 grams of carbon dioxide per kilowatt hour across all time periods. New South Wales and Queensland also exceed 700 grams during the afternoon and evening, which aligns with peak residential and commercial energy demand. These time blocks place additional pressure on the grid and lead to increased use of fossil fuel generation.

In contrast, South Australia and Tasmania appear as the lowest emitting regions. South Australia remains below 300 grams in all time periods, while Tasmania drops to below 140 grams in the morning. This suggests that renewable energy output in these regions is closely matched to daytime consumption, particularly from hydro and wind sources.

Across all five regions, afternoon and evening are the most carbon intensive periods due to high demand and lower solar availability. Regions that depend on fossil fuels show stable but high emissions throughout the day, while those with strong renewable integration display more variation and greater efficiency during daylight hours. These results reinforce the broader insight that increasing the share of clean energy in the grid not only reduces overall emissions but also helps smooth carbon intensity across different times of the day.

13. Carbon Emission Intensity by User Type Across NEM Regions

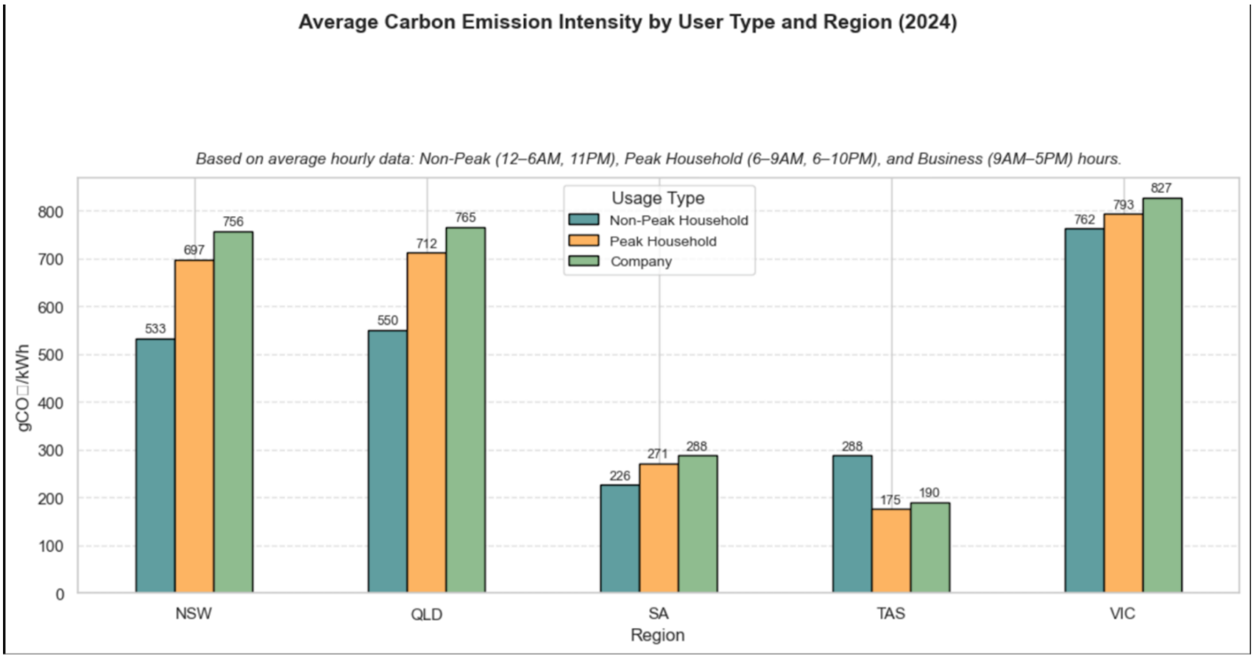


Figure 13 Average Carbon Emission Intensity by User Type and Region

Electricity usage was analysed by user type, specifically households and companies, to assess differences in average carbon emission intensity across the five major regions of the National

Electricity Market. These regions include New South Wales, Queensland, South Australia, Tasmania, and Victoria. To accurately reflect residential behaviour, household electricity consumption was divided into two time periods. Peak hours were defined as 6:00 AM to 9:00 AM and 6:00 PM to 10:00 PM, representing typical periods of high energy use in homes. Non peak hours were set from midnight to 5:59 AM and from 10:00 PM to 11:59 PM. Company electricity use was measured during regular business hours, from 9:00 AM to 5:00 PM.

Figure 13 reveals noticeable differences in carbon emission intensity across user types and regions. In New South Wales, Queensland, and Victoria, company electricity use results in significantly higher emissions compared to household usage. This is because commercial activity during daytime hours relies heavily on fossil fuel based power generation. In contrast, household electricity use during non peak hours is considerably cleaner, especially in New South Wales and Queensland, where emissions drop to 533 and 550 grams of carbon dioxide per kilowatt hour, respectively. These figures highlight the benefit of shifting household energy use to quieter periods of the day.

South Australia and Tasmania show much smaller differences between household and company emissions. This reflects a more stable and clean energy mix, driven by wind power in South Australia and hydroelectric generation in Tasmania. Notably, Tasmania is the only region where household emissions during peak hours are slightly higher than company emissions. This outcome is likely caused by fluctuations in renewable energy output during evening periods when residential demand is high.

Overall, the findings show that the timing of electricity use plays an important role in determining carbon efficiency. While company usage tends to be more emission intensive, households that use electricity during non peak times are generally better aligned with cleaner sources of energy. Tasmania remains a unique case, demonstrating how renewable variability can influence emission outcomes even in cleaner grids.

14. South Australia: A Benchmark for Balanced Low-Emission Energy Use

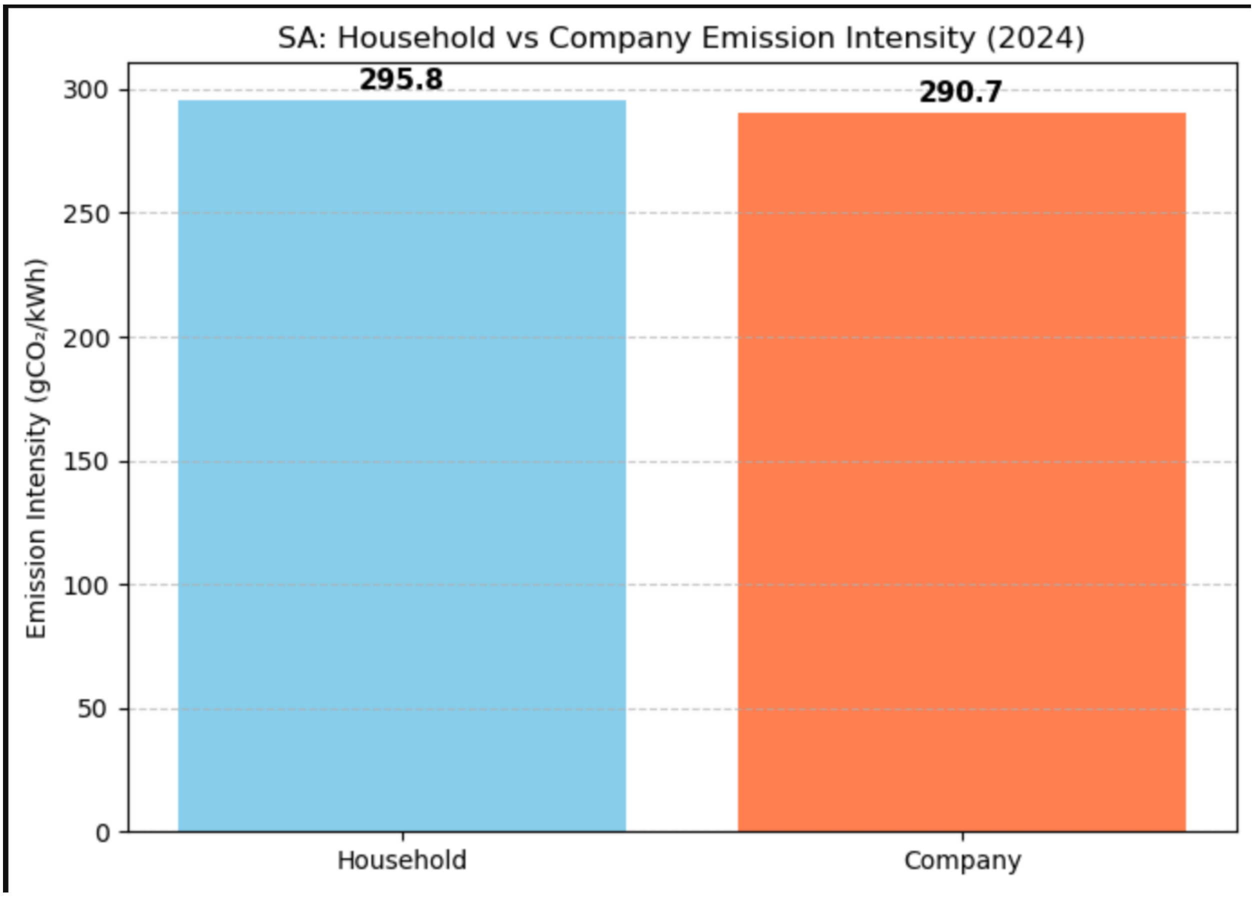


Figure 14 South Australia: Household vs Company Emission Intensity

This stable performance can be attributed to South Australia's diverse renewable energy mix, which allows the grid to supply clean electricity throughout the day and evening. The benefits of this reliability extend to several groups. Households looking to reduce their carbon footprint can use electricity at any time with limited environmental impact. Businesses aiming to meet sustainability goals or carbon neutrality targets can operate during normal hours without increased emissions. In addition, electric vehicle users benefit from steady access to cleaner energy for charging at any time of day.

15. Intra-Daily Emission Trends and Household vs Company Footprint

This section examines the pattern of carbon emission intensity throughout the day across regions in Australia’s National Electricity Market. It also evaluates whether households or companies contribute more to carbon emissions based on the times at which they consume electricity.

Across most regions, the daily emission curve follows a wave shaped trend. Emission levels are lowest during the late night and early morning hours, from midnight to 6:00 AM. This is when demand is low and renewable supply remains steady. Emissions then rise sharply in the morning and reach their peak during the afternoon hours, between 12:00 PM and 5:00 PM, which aligns with commercial and industrial activity. After sunset, emissions begin to fall again in the evening as overall demand decreases.

This daily pattern reflects the relationship between energy usage and the generation sources available throughout the day. Solar energy contributes significantly during midday, but its supply drops off in the evening, often requiring additional support from coal and gas-based generation.

Regionally, Victoria, New South Wales, and Queensland tend to show the highest emission levels during the afternoon, which indicates a strong dependence on fossil fuels during daytime operations. In contrast, Tasmania and South Australia maintain lower and more stable emission profiles across the day. This consistency is the result of a greater share of energy from hydro and wind sources. Nighttime emission levels are generally lower in all regions, showing that cleaner energy sources are more available during periods of reduced demand.

When comparing households and companies, households typically use electricity during the morning from 6:00 AM to 9:00 AM and in the evening from 6:00 PM to 10:00 PM. Companies tend to operate primarily during business hours, from 9:00 AM to 5:00 PM. The bar chart below presents the average carbon emission intensity during these household and company usage periods across the major regions in 2024.

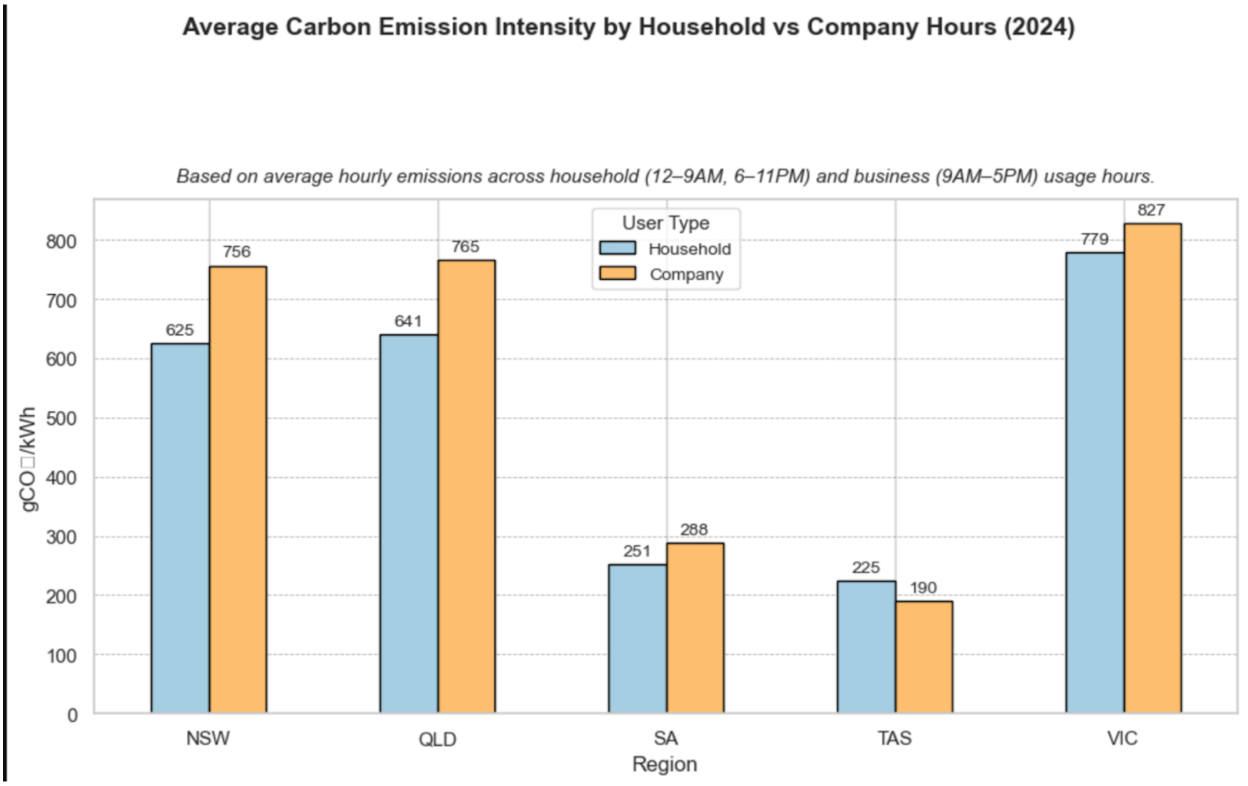


Figure 15 Average Carbon Emission Intensity by Household vs Company Hours

The comparison reveals several important patterns across regions. In New South Wales, Queensland, and Victoria, company electricity usage results in higher carbon emission intensity compared to household usage. In Victoria, company usage peaks at 827 grams of carbon dioxide per kilowatt hour, marking the highest observed value. In these states, household electricity use, particularly during non-peak night hours are noticeably cleaner.

Tasmania presents an exception to this trend. In this region, company emissions are slightly lower than household emissions, averaging 190 grams compared to 225 grams. This difference is likely due to fluctuations in renewable energy supply during evening hours when residential demand increases.

Companies, in contrast, tend to operate during high demand periods when carbon intensity is elevated. These insights support the importance of shifting business energy use to cleaner time blocks or adopting renewable solutions within commercial operations to reduce overall emissions.

Considering the typical consumption pattern of a household or company, households are more likely to have a lower emission intensity per kilowatt hour of electricity use. This underscores the value of encouraging time-conscious electricity use among households and developing targeted strategies to reduce daytime business-related carbon intensity through demand shifting or renewable sourcing.

16. Time-of-Day Impact on Carbon Emission Intensity Across Regions

Understanding how carbon emission intensity changes over the course of the day is essential for developing effective and cleaner energy consumption strategies. This section examines how average emissions, measured in grams of carbon dioxide per kilowatt hour, vary throughout the day across five major regions in the National Electricity Market. These regions include New South Wales, Queensland, South Australia, Tasmania, and Victoria. The analysis is structured around four key time intervals: night from midnight to 6:00 AM, morning from 6:00 AM to noon, afternoon from 12:00 PM to 6:00 PM, and evening from 6:00 PM to midnight.

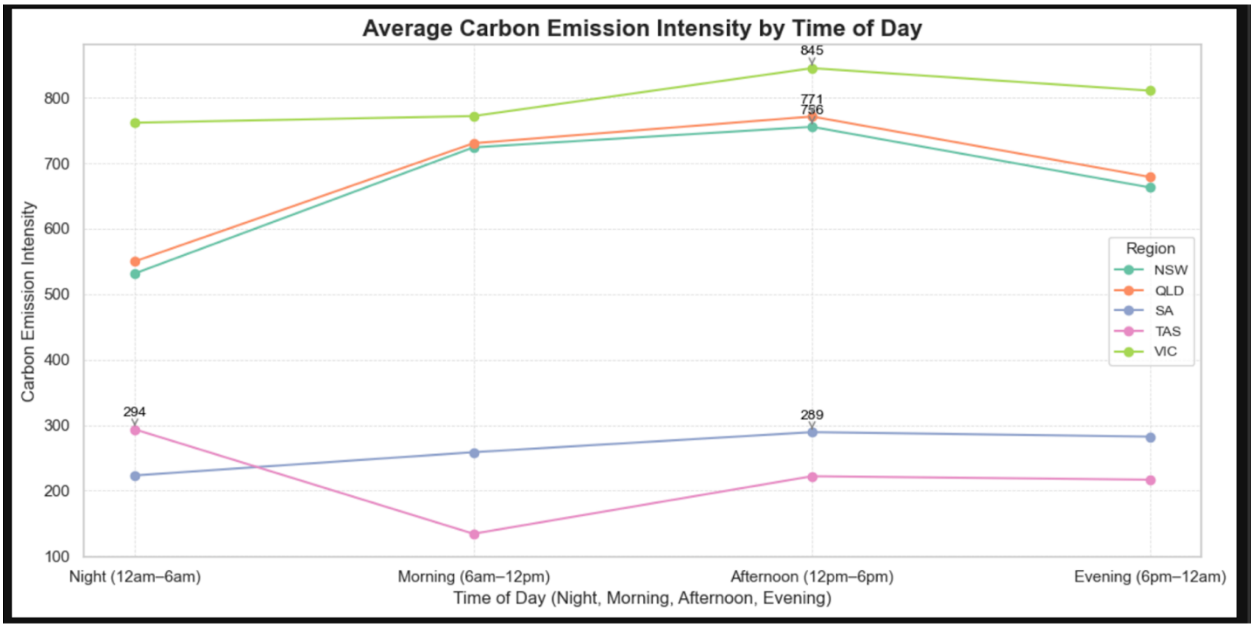


Figure 16 Average Carbon Emission Intensity by Time of Day

Afternoon remains the most carbon intensive period in Victoria, New South Wales, and Queensland, which aligns with commercial and industrial activity relying on fossil fuel generation. Morning and evening periods also carry notable emissions in most regions due to household consumption.

These results highlight the importance of shifting energy use to periods with cleaner supply and investing in regional renewable infrastructure. Doing so can help reduce daily peaks in emissions and support the broader transition to a low carbon electricity system.

17. Company Electricity Usage Patterns: Daily, Monthly, and Hourly Trends

To understand the operational behavior of companies and its implications for emission management, this section examines electricity consumption across three time scales: hourly, monthly, and daily. These usage patterns help contextualize emission intensity findings and provide insight into when and how companies use electricity.

17.1 Hourly Consumption Profile

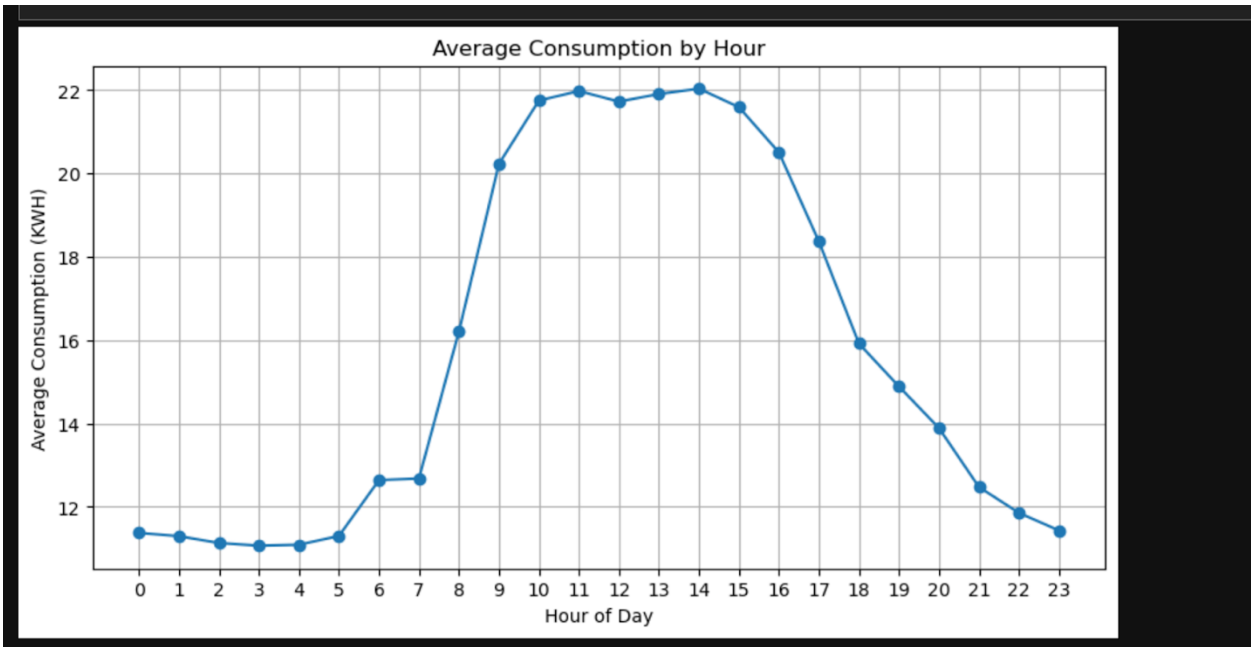


Figure 17.1 Average Company Consumption by Hour

Figure 17.1 illustrates the average company electricity usage, measured in kilowatt hours, across a full 24 hour period. The pattern reveals several important trends. During the night, from midnight to 5:00 AM, electricity use is at its lowest, reflecting minimal activity and limited operation of essential systems such as servers or security lighting. A sharp increase in consumption occurs between 6:00 AM and 9:00 AM, marking the start of the workday. This rise is likely driven by lighting, heating or cooling systems, and the activation of equipment.

From 10:00 AM to 4:00 PM, electricity use remains consistently high, averaging around 22 kilowatt hours. This period represents peak business operations, where most systems and machinery are fully engaged. After 5:00 PM, usage gradually declines as employees finish work and systems begin to power down. By around 11:00 PM, consumption returns to its early morning levels, indicating that most business activities have ceased.

This profile highlights the strong link between business hours and electricity demand. It also explains why company energy use often overlaps with high carbon emission periods, as identified in earlier sections of the report. The concentration of commercial activity during the daytime aligns with higher fossil fuel generation and contributes to elevated emission levels during these hours.

17.2 Monthly Electricity Consumption (May 2022 – May 2023)

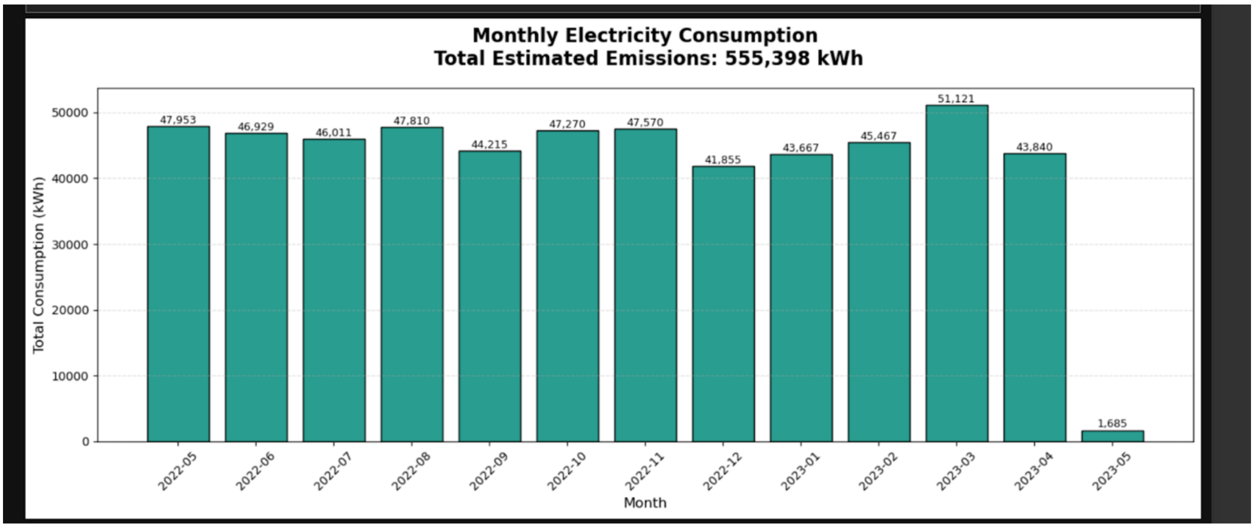


Figure 17.2 Monthly Company Electricity Consumption

Figure 17.2 presents the total monthly electricity usage over a one-year period, offering a clear view of consumption trends. From May 2022 to April 2023, electricity use remained relatively stable, ranging between approximately 42,000 and 48,000 kilowatt hours. This consistency reflects routine operations and suggests a well-established baseline for business activity.

There are a few notable seasonal variations. In July 2022, electricity use reached 47,810 kilowatt hours, likely driven by increased heating needs during winter. Another peak occurred in March 2023, with usage rising to 51,121 kilowatt hours, which may be linked to post holiday business ramp up or short term project activity. A decline was observed in December 2022, when usage dropped to 41,855 kilowatt hours. This is likely due to holiday closures or reduced staffing levels.

A sharp and unexpected decrease is shown for May 2023, with electricity use recorded at just 1,685 kilowatt hours. This value is significantly lower than all other months and is likely the result of a data reporting issue rather than an actual operational change. It should be noted and possibly excluded from overall trend analysis.

The monthly trend indicates that the company's electricity demand is largely predictable. This consistency provides a solid foundation for implementing load management strategies and targeting emissions reductions during higher usage periods.

17.3 Daily Consumption Pattern and Seasonal Drop

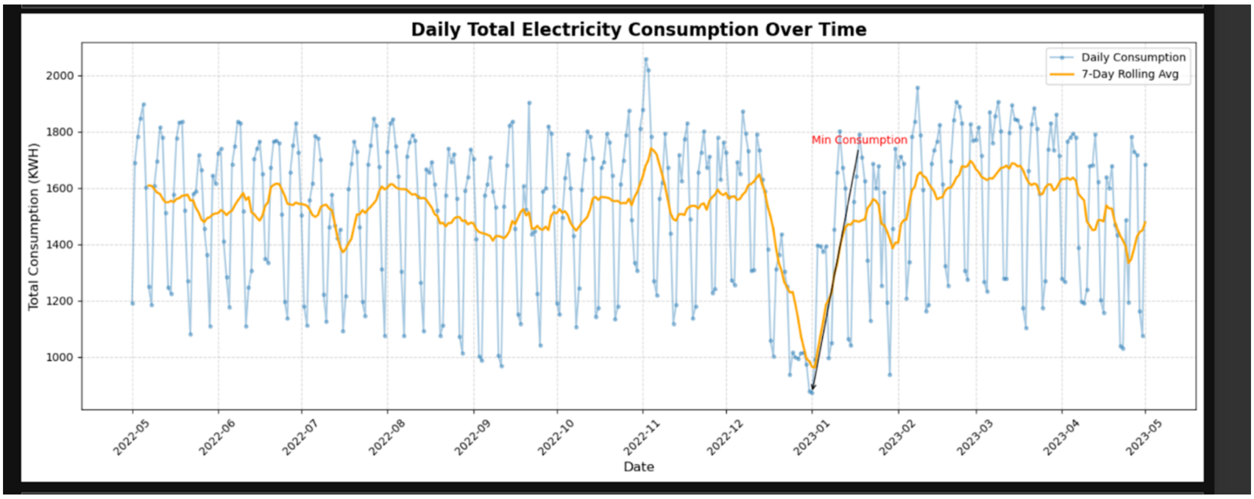


Figure 17.3 Daily Total Electricity Consumption Over Time (Company)

Figure 17.3, shown with a seven day rolling average, offers a more detailed view of how usage fluctuates throughout the year. The data reveals high frequency variation in daily consumption, likely influenced by changes in machinery use, staffing levels, and other operational factors. A notable decline in electricity use occurs between late December 2022 and early January 2023. This drop reflects a holiday shutdown period and corresponds with the lower monthly total recorded for December.

Electricity consumption gradually returns to normal levels through January and February 2023, confirming that the decline was temporary and tied to seasonal closures rather than data reporting issues. The chart supports earlier findings by highlighting regular business patterns and verifying that December's lower consumption was due to reduced operations.

Taken together, the daily, monthly, and hourly visualisations show that business energy consumption is heavily concentrated during daytime hours and generally consistent across the year, with predictable dips during holidays. These patterns align closely with periods of higher carbon emissions, positioning companies as key targets for emission reduction initiatives. Strategies such as shifting energy loads to cleaner periods, adopting on site solar generation, and optimising heating, ventilation, and lighting systems during daytime hours can help reduce emissions and improve efficiency.

18. Decarbonization Outlook

Key findings show that fossil fuel dominant states like Victoria and New South Wales consistently record the highest carbon intensities, particularly during afternoon and business hours. In contrast, renewable rich states such as South Australia and Tasmania demonstrate cleaner, more flexible emission profiles especially during midday periods when solar and hydro resources are most active. Intra-daily curves highlight the carbon burden of daytime operations, while seasonal and cumulative analyses reinforce the long-term environmental impact of continued fossil fuel reliance.

Moreover, the distinction between company and household electricity use reveals that businesses, which consume electricity during peak daytime hours, are generally more carbon intensive than households. Household usage, especially during off-peak periods such as late night and early morning, tends to align better with cleaner energy availability. This makes households key contributors to emission efficiency, particularly in regions where renewable supply remains strong outside of traditional business hours.

South Australia stands out as a benchmark for balanced and low-emission energy usage, offering valuable lessons in renewable integration and grid stability. Its ability to maintain clean electricity supply across both residential and commercial time blocks reflects the success of a diversified renewable energy portfolio.

Collectively, these insights point toward a path for emission reduction that includes:

- Load shifting to align consumption with low emission periods
- Investment in renewables and storage, particularly in fossil dominant regions
- Efficiency upgrades in commercial operations
- Targeted policy design that encourages clean energy use across all user groups

Australia's decarbonisation journey will require both structural reform and behavioural change. By aligning electricity consumption with cleaner energy windows, empowering households to make low-emission choices, and supporting region-specific renewable strategies, stakeholders across the NEM can drive meaningful progress toward a low-carbon future.

19. Box Plot Analysis: Bid Prices by Generation Type

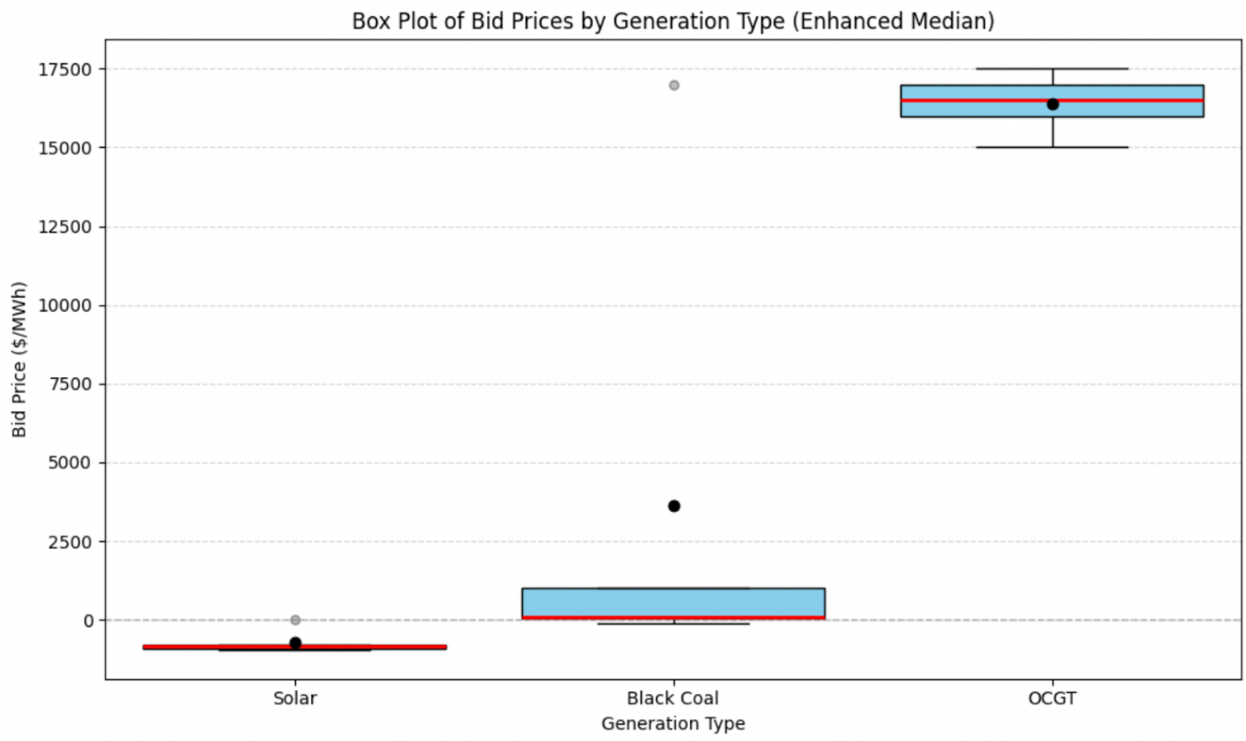


Figure 19 Distribution of Bid Prices by Generation Type

Figure 19 illustrates the variation in bid prices across three major generation types: Solar, Black Coal, and OCGT (Open Cycle Gas Turbines). As shown,

- **solar bids** are tightly clustered around negative values, highlighting their must-run nature and near-zero marginal costs. These generators often bid negatively to ensure dispatch, particularly during daylight hours when solar output is highest.
- **Black Coal** exhibits a wider range of bid prices, with the median just above zero. This reflects the dual role of coal generators: they bid low to remain dispatched as base-load providers, while also using higher bands to respond to market fluctuations and ramping needs.

In contrast,

- **OCGT** units consistently bid at the upper end of the market price range, with median values near the market cap. This is expected, as OCGT plants are designed to operate during peak demand periods, making high bids necessary to cover their startup and running costs.

Overall, the plot clearly demonstrates how bidding behaviour is influenced by the economic and operational characteristics of each generation type.

20. Time-of-Day Bidding Strategy

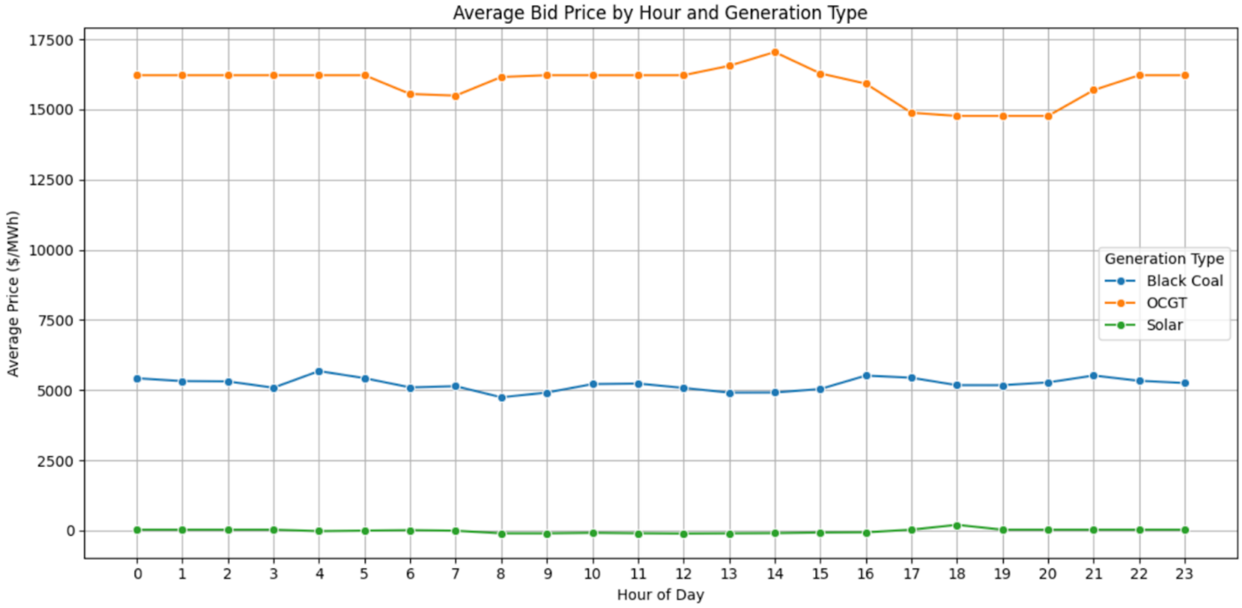


Figure 20 Average Bid Price by Hour and Generation Type

Average bid prices by hour reveal how generator types respond to changing demand over a 24-hour period:

- **Solar bids** remain low throughout the day (mostly < $0), increasing slightly only during late evening. This mirrors solar's natural availability curve.
- **OCGT bids** remain the highest across all hours, peaking around 2 PM to 8 PM, indicating strategic use during high-demand periods.
- **Black Coal bids** are relatively stable across the day, with mild peaks during morning and evening demand surges.

21. Aggregated Supply Curve Comparison

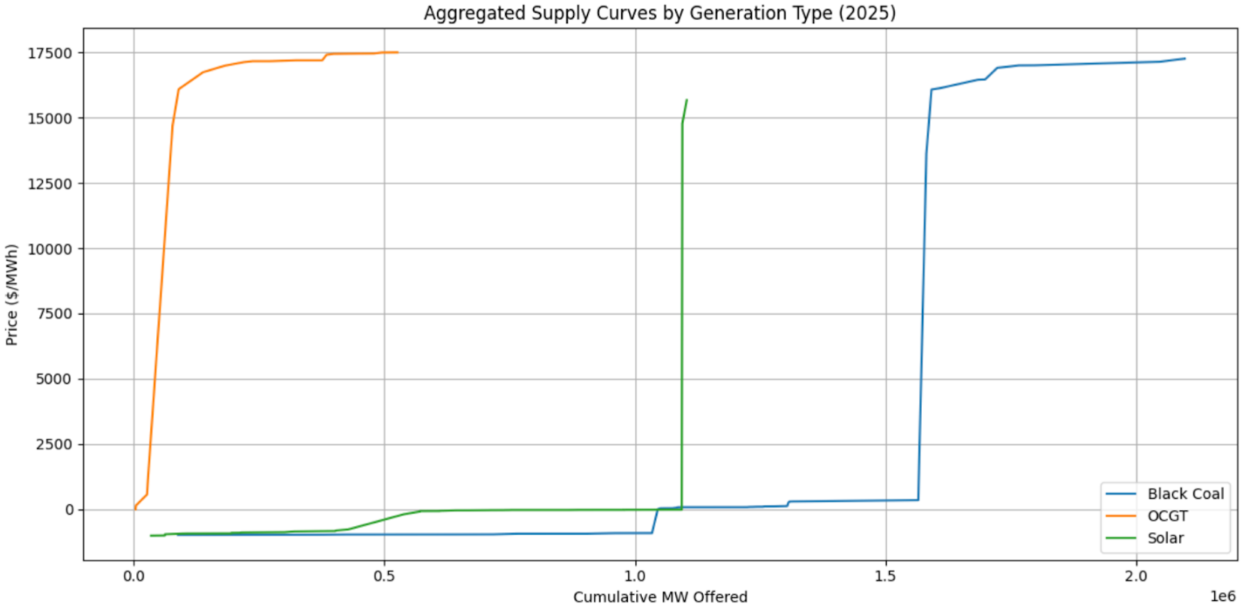


Figure 21 Aggregated Supply Curves by Generation Type (2025)

Figure 21 visualizes how much capacity each generator type offers at increasing price points.

- **Solar** offers a large amount of electricity at **very low prices**, maintaining a flat curve—indicating uniform low-price bidding.
- **OCGT** offers a **small amount** at **very high prices**, resulting in a steep vertical curve—suited for short-term, high-reward dispatch.
- **Black Coal** shows a **tiered strategy**, bidding more at lower prices and incrementally higher at upper bands to match market conditions.

22. Comparison of Total Electricity Supply (MW) by Generation Type During Peak and Off-Peak Hours

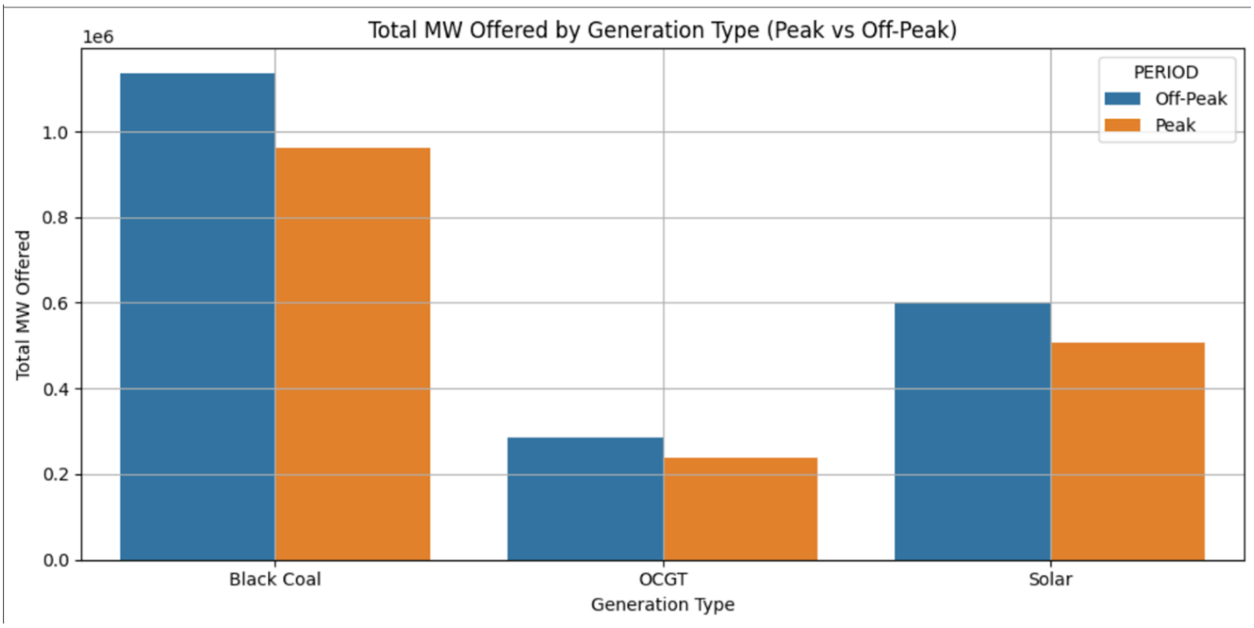


Figure 22 Total MW Offered by Generation Type (Peak vs Off-Peak)

Figure 22 compares the total megawatts (MW) offered by each generation type Black Coal, OCGT (gas), and Solar across Peak and Off-Peak periods.

- **Black Coal** provides the highest and most consistent supply, offering large volumes in both peak and off-peak hours. This reflects its role as a base-load generator that runs continuously.

- **Solar** contributes significantly during both periods, but the slightly lower peak contribution is likely due to the defined peak periods including early morning and evening, when solar output drops. This highlights solar's daylight dependency.

- **OCGT** offers much lower MW overall, with slightly more during off-peak. This may seem counterintuitive, but it's due to OCGT's role as a reserve or emergency generator, only operating during short, high-price intervals but not across long continuous blocks.

Overall, Figure 22 shows how different technologies serve distinct operational roles in the electricity market with coal providing steady base-load, solar peaking during sunlight hours, and OCGT stepping in during demand spikes.

23. Forecast of Solar MW Supply Based on April 2025 Data

- The historical solar output shows a strong daylight pattern high MW during 6 AM to 6 PM and flat near zero at night.
- The forecast (orange line) is smoother, representing the expected pattern for the next 24 hours using recent trends.
- The forecast shows continued solar availability during the day and confirms how solar output can be predictable and stable, especially when averaged across several days.

24. Generator Bidding Strategies by Technology

The bidding behaviour of generators in the NEM during April 2025 clearly reflects the economic roles and physical characteristics of each technology:

- **Solar** consistently bids at or below $0/MWh to maximise dispatch during daylight hours, offering high volumes during off-peak times but declining sharply in the evening.
- **OCGT** (gas turbines) submits extremely high bids, reflecting its role as a peaking generator. It contributes low volumes and is only active when prices are high, regardless of the time.
- **Black Coal** plays a central role as a baseload generator, offering large volumes at moderate prices throughout the day, with a tiered bidding strategy that adapts to demand conditions.

25. Distribution of Bidded Prices by Technology Type (2019 vs 2025)

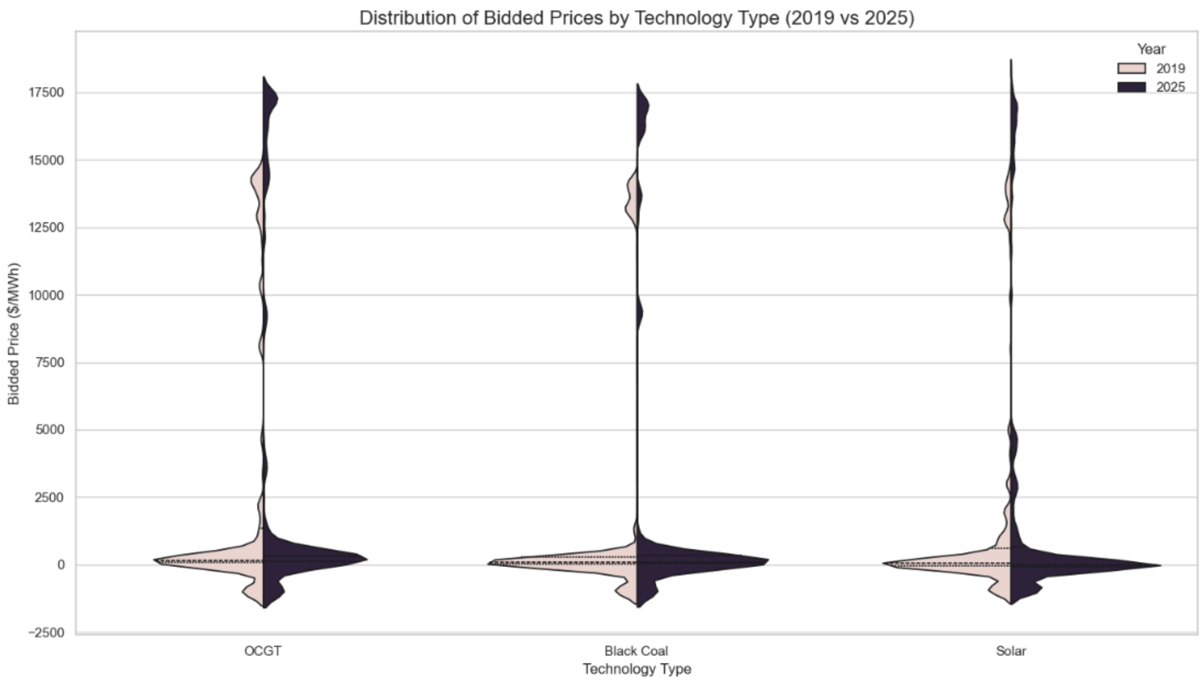


Figure 25 Distribution of Bidded Prices by Technology Type (2019 vs 2025)

Observation: The violin plot displays the full distribution of bidded prices for OCGT (Open Cycle Gas Turbine), Black Coal, and Solar technologies, split by year.

- For **OCGT** and **Black Coal**, both 2019 and 2025 distributions show a significant concentration of bids at lower price points (near zero), but also a substantial, albeit less dense, tail extending to very high prices (above 15,000 $/MWh). The 2025 distribution for both, specifically OCGT, appears slightly wider or with more density at higher prices than 2019 for the upper tail, but also possibly a tighter concentration at the lowest prices.
- For **Solar**, the bulk of bids in both years are concentrated at very low (or even negative) prices. However, in 2025, the solar distribution also exhibits a more pronounced tail extending to higher prices, similar to the thermal plants, which was less apparent in 2019.

Interpretation:

- **Dual Role of Thermal Generation (OCGT, Black Coal):** The shape suggests OCGT and Black Coal fulfill a dual role: bidding at very low prices to capture energy demand (likely when conditions favor them or as base-level commitment), and also bidding at very high prices to reflect scarcity pricing, system contingency, or the provision of critical capacity/flexibility services. The *reduction* in the extreme upper tail density for these in 2025 indicates that the market might be experiencing fewer extreme scarcity events that trigger prices above 10,000 $/MWh, or that strategic bidding at these extreme levels is less frequent.
- **Solar's Evolving Value Capture:** Solar's growing density of bids at higher prices in 2025 implies that it's either part of hybrid plants (e.g., solar + battery) that can bid firmer or provide ancillary services, or that some solar capacity is now being bid strategically to capture more value beyond simple marginal energy dispatch. This suggests a maturing Solar market.

26.Volatility/Spread of Bidded Prices by Technology Type (2019 vs 2025)

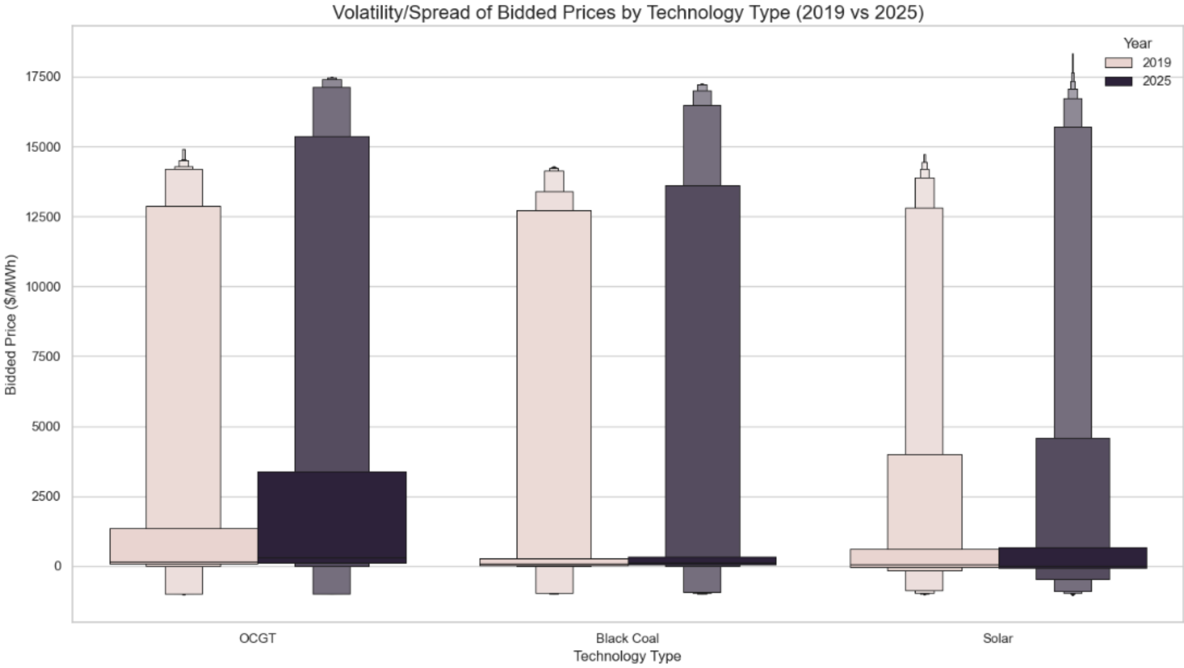


Figure 26 Volatility/Spread of Bidded Prices by Technology Type (2019 vs 2025)

Observation:

- **OCGT:**

  I. 2019: The spread ranges from approximately 0 to 13,000 $/MWh, with a significant portion concentrated below 2,500 $/MWh.

  II. 2025: The spread extends slightly higher, up to around 14,000 $/MWh, with a noticeable increase in the upper range (above 10,000 $/MWh) and a tighter concentration at lower prices (below 2,500 $/MWh).

- **Black Coal:**

  I. 2019: The spread ranges from 0 to about 15,000 $/MWh, with a dense concentration around 0-2,500 $/MWh and a tapering tail to higher prices.

  II. 2025: The spread remains similar (up to ~15,000 $/MWh), but the upper tail appears less dense, with a more pronounced concentration at lower prices (0-2,500 $/MWh).

- **Solar:**

  I. 2019: The spread is narrow, ranging from 0 to around 12,500 $/MWh, with most bids concentrated near 0 $/MWh.

  II. 2025: The spread extends significantly higher, up to approximately 17,500 $/MWh, with a broader range and a more pronounced upper tail compared to 2019.

Interpretation:

- OCGT: The slight increase in the upper price range in 2025 suggests that OCGT is bidding higher to reflect increased value for flexibility or rising operational costs (e.g., gas prices). The tighter low-price concentration indicates more consistent low-cost bidding, possibly to secure dispatch during favorable conditions.
- Black Coal: The stable upper limit but reduced density in the high-price tail in 2025 indicates fewer extreme scarcity bids. This could reflect improved supply adequacy, market rule changes, or a strategic shift to mid-range pricing to recover costs, aligning with a reduced reliance on extreme scarcity pricing.
- Solar: The dramatic expansion of the upper price range in 2025, reaching 17,500 $/MWh, suggests solar is increasingly involved in higher-value market products (e.g., hybrid systems with batteries) or strategic bidding. The broader spread indicates a maturing market where solar captures more diverse revenue streams beyond low marginal cost energy.

27. Average Bidded Price by Hour of Day (2019 vs 2025)

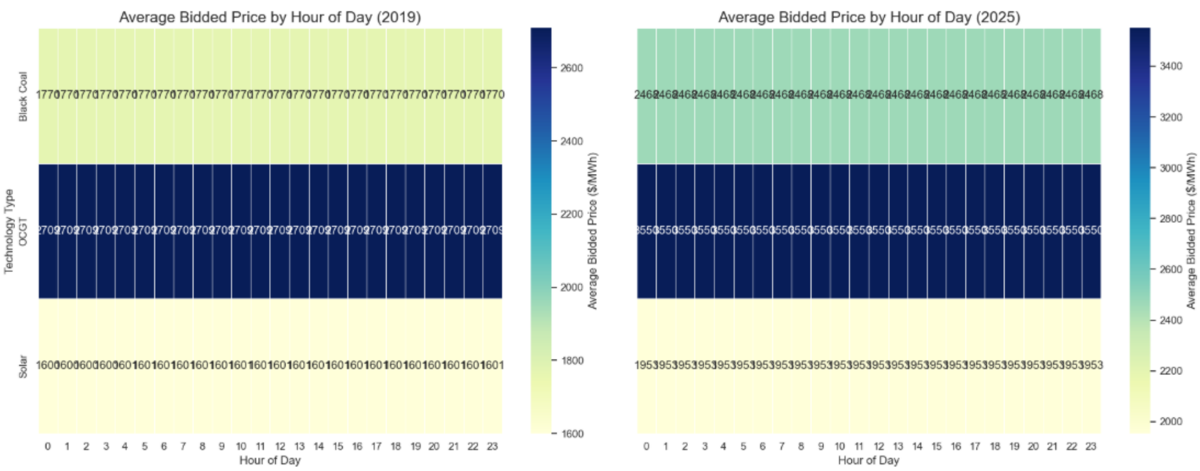


Figure 27 Average Bidded Prices by Hour of Day (2019 vs 2025)

Observation: These heatmaps show the average bidded price for Black Coal, OCGT, and Solar across 24 hours.

- **Black Coal:** In 2019, Black Coal's average bidded price is consistently around **1770 $/MWh** across all hours. In 2025, it rises to **2400 $/MWh**.
- **OCGT:** In 2019, OCGT's average bidded price is consistently around **2700 $/MWh** across all hours. In 2025, it rises to **3050 $/MWh**.
- **Solar:** Solar bids are consistently low in 2019 (around **1600 $/MWh**), particularly during daytime hours. In 2025, solar bids are still low but show a slight increase to around **1953 $/MWh** during daytime hours, and are not visible for nighttime hours (implying minimal or no bids during those times).

Interpretation:

- **Thermal Generators (Black Coal & OCGT) – Increasing Price Demands:** The systematic increase in average hourly bid prices for both Black Coal and OCGT signifies that these dispatchable units are facing higher operational costs or are strategically valuing their dispatchability more highly. As Solar penetrates the market, these thermal plants are less about "baseload" and more about "flexibility" and "reliability," for which they are demanding a higher average price when dispatched. This suggests:
    1. **Increased Marginal Operating Costs:** Higher fuel costs (e.g., global coal or gas prices), increased carbon costs or environmental compliance burdens, or rising operational and maintenance (O&M) expenses could be pushing up their bid prices.
    2. **Strategic Bidding for Scarcity/Capacity:** As baseload demand is increasingly met by low-cost renewables, these thermal generators might be **strategically bidding higher to ensure profitability** during the fewer hours they are dispatched. They are no longer just competing on energy volume but are pricing in the **value of their dispatchability, reliability, and contribution to system security** during periods of lower renewable output or high demand. They need to recover their fixed costs over potentially fewer operational hours, leading to higher bids when they do operate.
    3. **Market Structural Shifts:** The market might be valuing firm capacity higher, or there could be a reduction in overall thermal capacity, leading to less competition among themselves and allowing higher price bids.
    4. **Role Shift:** This reinforces the idea that their primary role is shifting from pure baseload energy providers to providers of critical flexible or peaking capacity, which commands a premium.
- **Solar – Continued Low Bidding, Slight Increase:**
- Solar's Role in Price Suppression (Daytime): Solar maintains its role as a key driver of low daytime prices. The slight increase in Solar's average bid price in 2025 (from 160 to 195) is negligible compared to the thermal increases and still reflects its low marginal cost nature. This could still indicate that:
    1. **Opportunity Costs:** Even at very low prices, some solar bids might be reflecting minor opportunity costs or minimum revenue requirements.
    2. **Market Access Costs:** Small but increasing fixed costs associated with market participation or grid connection.
    3. **Hybrid Operation:** If this data includes solar with storage, the storage component might slightly increase the average bid price even during solar generation hours.
- **Overall Market Dynamics:** The combination of increasing thermal bid prices and high renewable penetration indicates a complex market where the overall energy price might be driven down by renewables, but the **price of *dispatchable capacity* or *firmness* is increasing**. This highlights the ongoing challenge of integrating high levels of variable renewable energy and ensuring system reliability, which necessitates premium payments for flexible resources, the narrative of increasing supply (particularly renewables) pushing down average bidded prices in the market.

28. Distribution of Bidded Prices by Region (2019 vs 2025)

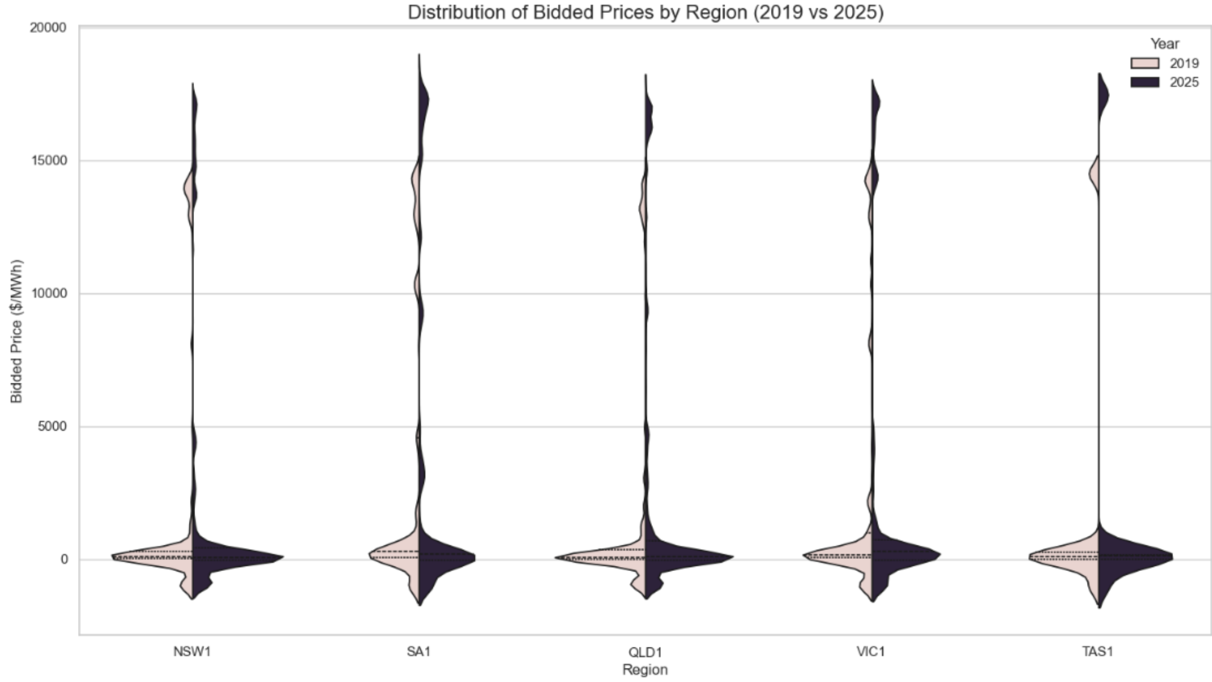


Figure 28 Distribution of Bidded Prices by Region (2019 vs 2025)

Observation: Similar to the technology-specific violin plot, this shows the bidded price distribution for each region (NSW1, SA1, QLD1, VIC1, TAS1), split by year.

- All regions exhibit the characteristic dual-regime bidding: a dense concentration at low prices and a substantial tail of high-price bids.
- For most regions, the low-price concentration in 2025 appears slightly wider and potentially shifted to slightly higher prices compared to 2019, while the high-price tail also seems to persist or even be more pronounced in 2025 for some regions.
- TAS1 (Tasmania) shows a somewhat different profile, with a potentially tighter distribution at lower prices, and its high-price tail may be less pronounced than other regions, especially in 2025.

Interpretation:

- **Regional Market Similarities:** The pervasive dual-price regime across all major NEM regions highlights the common market mechanisms that allow for both marginal cost-based bids and scarcity/capacity-based bids.
- **Increased High-Price Bidding:** The continued or even slightly more pronounced high-price tails in 2025 for several regions suggest that even with increased overall supply (particularly renewables), regional price spikes or the necessity for very high-priced dispatchable generation persist. This could be due to:

- **Transmission Constraints:** Congestion between regions can isolate markets, leading to local scarcity.
- **Local Supply Shortfalls:** Specific regional demand-supply imbalances.
- **Ancillary Services Needs:** High bids for frequency control or other grid services.

- **Tasmania's Unique Profile:** TAS1's potentially tighter, lower-price distribution, especially in 2025, could be attributed to its high reliance on hydropower, which has very low marginal costs and may offer more consistent, predictable, and dispatchable low-cost energy without as much reliance on extreme high-price bids compared to fossil-fuel dominant regions.

29. Correlation Matrix of Bidded Quantity by Technology (2019 vs 2025)

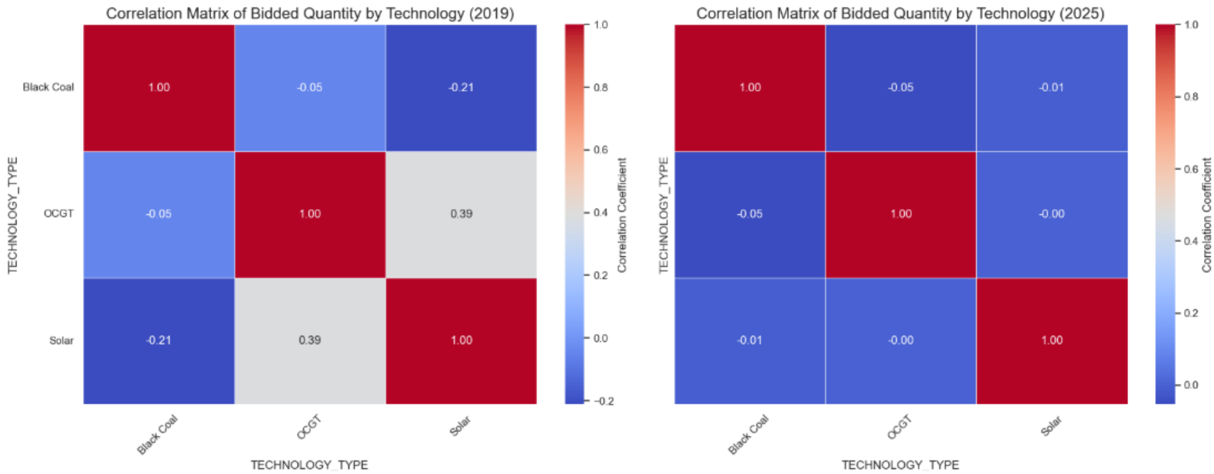


Figure 29 Correlation Matrix of Bidded Quantity by Technology (2019 vs 2025)

Observation: These heatmaps show the correlation coefficient between the bidded quantities of different technology types.

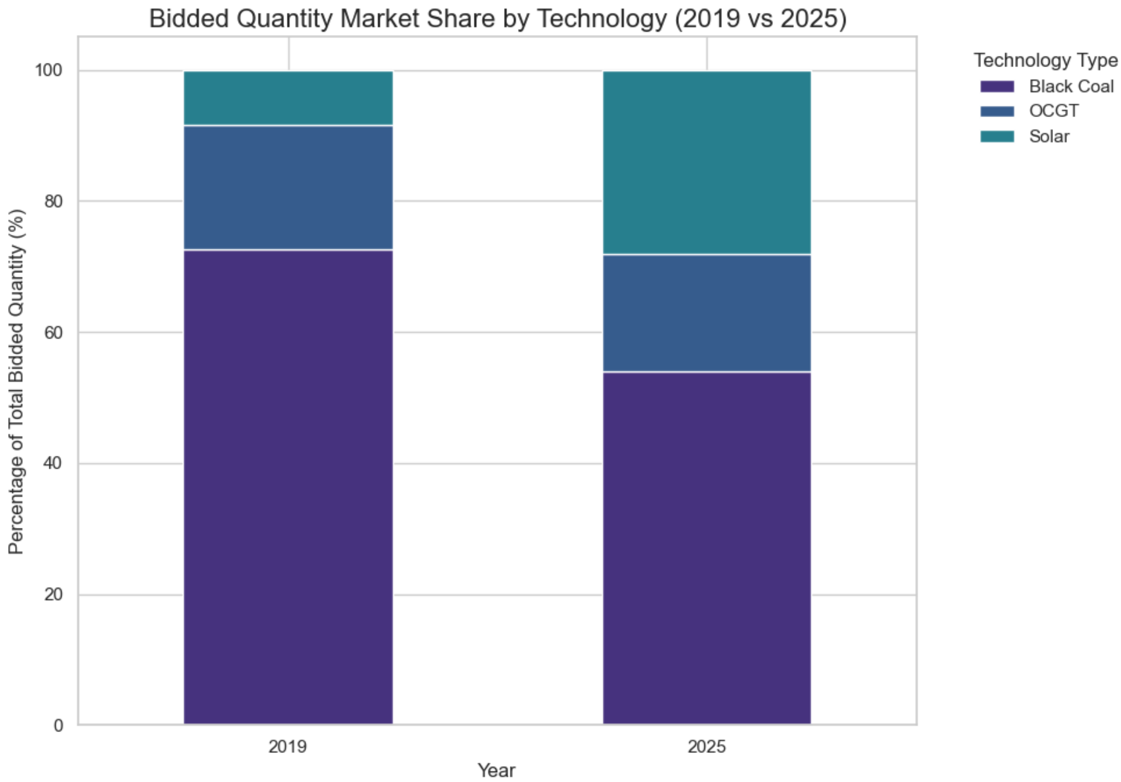
- **2019:**
  - Black Coal vs. OCGT: -0.05 (very weak negative correlation)
  - Black Coal vs. Solar: -0.21 (weak negative correlation)
  - OCGT vs. Solar: 0.39 (moderate positive correlation)
- **2025:**
  - Black Coal vs. OCGT: -0.05 (very weak negative correlation - same as 2019)
  - Black Coal vs. Solar: -0.01 (virtually no correlation - significantly less negative than 2019)
  - OCGT vs. Solar: -0.00 (virtually no correlation - a drastic change from 2019's moderate positive)

Interpretation:

- **Decoupling of Renewables and Thermal:** The most striking change is the shift in correlation with Solar.

    - The correlation between Black Coal and Solar moving from -0.21 to -0.01 suggests that in 2025, **Solar's bidded quantity is no longer as inversely related to Black Coal's as it was in 2019.** This could mean that Solar's growth is so significant that it's simply increasing its bids regardless of coal's output, or that coal is reducing its bids irrespective of solar, or that they are operating in more distinct market segments.
    - The change from a moderate positive correlation (0.39) between OCGT and Solar in 2019 to virtually no correlation (-0.00) in 2025 is very telling. In 2019, OCGT and Solar might have occasionally been co-bidding or responding to similar demand signals (e.g., both ramping up during high demand periods, with OCGT providing flexibility). In 2025, their bidding behavior has **decoupled**. This implies OCGT's role is now much more independent of solar, likely focusing on distinct grid needs (e.g., evening peaks, rapid response, inertia) that aren't directly related to solar's generation profile.
  - **Consistent Thermal Relationship:** The very weak negative correlation between Black Coal and OCGT remains stable. This suggests their bidding patterns are not highly dependent on each other, often fulfilling different market roles (baseload vs. peaker/flexible) or responding to different cost drivers.
  - **Market Specialization:** The overall trend points towards **increased specialization** in the market. As solar becomes a dominant low-cost energy provider, other technologies are finding their niche roles, leading to less direct correlation in their bidded quantities.

30. Bidded Quantity Market Share by Technology (2019 vs 2025)



Observation: This stacked bar chart presents the proportional contribution of each technology type to the total bidded quantity.

- In **2019**, Black Coal dominates the market share (around 70%), followed by OCGT (around 20%), and then Solar (around 10%).
- In **2025**, the share of Black Coal significantly decreases (to around 50-55%). OCGT's share remains relatively stable or slightly decreases. Crucially, Solar's market share dramatically increases, now representing a much larger proportion (around 30-35%) of the total bidded quantity.

Interpretation:

- **Renewable Disruption:** This is perhaps the most direct visual evidence of the energy transition. The substantial increase in Solar's bidded quantity market share, coupled with the sharp decline of Black Coal's share, indicates a clear shift away from traditional fossil fuel dominance towards renewable energy.
- **Shift from Baseload:** The reduction in Black Coal's share implies a move away from constant, large-scale baseload generation being the primary energy source.
- **OCGT's Enduring Role:** The relatively stable share for OCGT suggests its continued importance, not necessarily for total energy volume but likely for its flexibility and ability to ramp up quickly to fill gaps left by variable renewables or to provide system stability. Its role is shifting from energy to capacity/flexibility.
- **Policy Effectiveness:** This shift strongly suggests that policies aimed at decarbonization and renewable energy deployment are having a tangible impact on the supply side of the electricity market.

31. Regional Bid Volume Share by Generation Technology (2019 vs 2025)

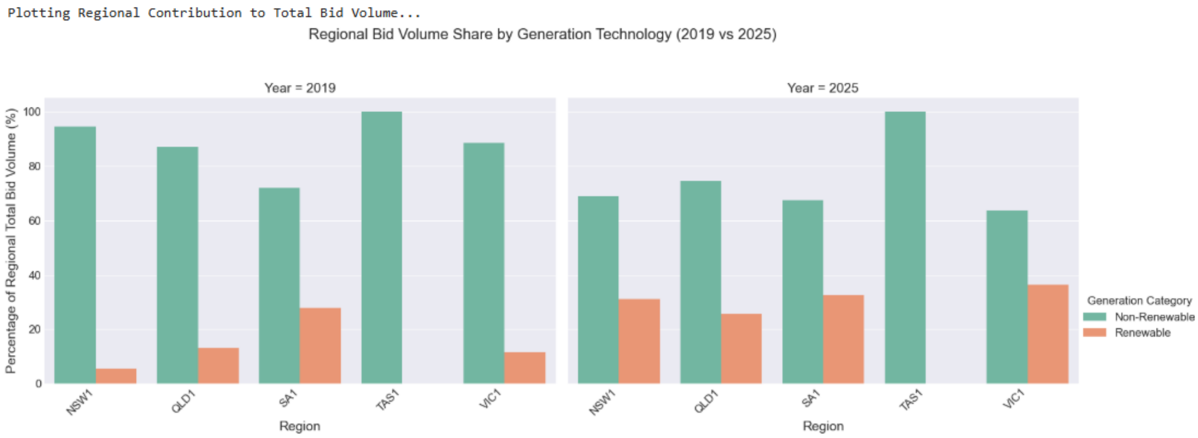


Figure 31 Regional Bid Volume Share by Generation Technology (2019 vs 2025)

Observation: This chart clearly disaggregates the total bidded quantity (or volume) in each region by two broad categories: "Non-Renewable" (mint green) and "Renewable" (peach/orange), for both 2019 and 2025.

- In **2019**: Non-Renewable generation dominates bid volume across all regions, typically accounting for **85-99%** of the total. Tasmania (TAS1) appears to be almost exclusively non-renewable in its bid volume, with other states showing very small renewable contributions.
- In **2025**:
  - **SA1** exhibits a noticeable shift, with Renewable bid volume increasing significantly to roughly **30-35%** of the total, while Non-Renewable drops to **65-70%**.
  - **VIC1** also shows a substantial increase in Renewable bid volume, reaching approximately **35-40%**, with Non-Renewable decreasing accordingly.
  - **NSW1** and **QLD1** show the most dramatic shift in Renewable bid volume, perhaps reaching over **30%** for NSW1 and around **25%** for QLD1.
  - **TAS1** continues to be dominated by Non-Renewable bid volume, with only a marginal increase in Renewable share, remaining close to its 2019 proportions.

Interpretation:

- **Solar's Impact on Regional Supply (SA1 & VIC1):** The substantial increase in Solar's bid volume share in SA1 and VIC1 directly correlates with the observed shifts in their respective aggregated supply curves. For SA1, a massive influx of low-marginal-cost Solar has significantly expanded the cheapest part of the bid stack. For VIC1, Solar's rise is filling a gap left by changes in older Black Coal operations (as inferred from its reduced low-price supply block), but the overall structure indicates that while Solar is providing cheap energy, the system still faces challenges in ensuring consistent dispatchable supply without reliance on high-priced OCGT/Black Coal when solar is not available.

- **Solar Growth vs. Thermal Dominance (NSW1 & QLD1):** The "dramatic shift" for Solar in NSW1 and QLD1 (reaching 30-35% and ~25% respectively) is highly significant. However, when juxtaposed with their aggregated supply curves, which show *higher overall prices* for comparable quantities in 2025, it reveals a critical dynamic:
  - Even with substantial Solar growth, the **remaining large share of Black Coal and OCGT** in these regions (65-70% in NSW1, ~75% in QLD1) is now **bidding at systematically higher price points**. This implies that the cost of operating Black Coal and OCGT has increased, or they are strategically bidding higher to recover fixed costs over potentially fewer dispatch hours, or to provide essential firmness. Solar is certainly growing its *volume*, but the thermal fleet is becoming more expensive or assertive in its pricing, preventing a wholesale price decline from Solar alone.
- **TAS1's Distinctive Mix:** The continued dominance of OCGT and Black Coal in TAS1 (and minimal Solar share) explains why its bid stack shows relative stability in its primary low-cost supply, with slight increases in high-priced contingency bids reflecting the value of flexible, dispatchable power in maintaining system stability.

- **Strategic Implications for Market Participants:** This data highlights where new Solar investment has been most impactful (SA1, VIC1). It also shows where thermal generators (OCGT, Black Coal) are adapting their bidding strategies – either due to rising operating costs or by leveraging their dispatchable nature to command higher prices in markets increasingly reliant on variable generation. For potential investors, this indicates the evolving risk and return profiles for different technologies in different regions.
  - **Targeted Policy Needs:** The differentiated regional shifts highlighted in the graph suggest that energy policy and investment strategies need to be regionally nuanced to address specific supply-demand balances, existing infrastructure, and the maturity of renewable integration in each state.

32. Aggregated Supply Curve: OCGT

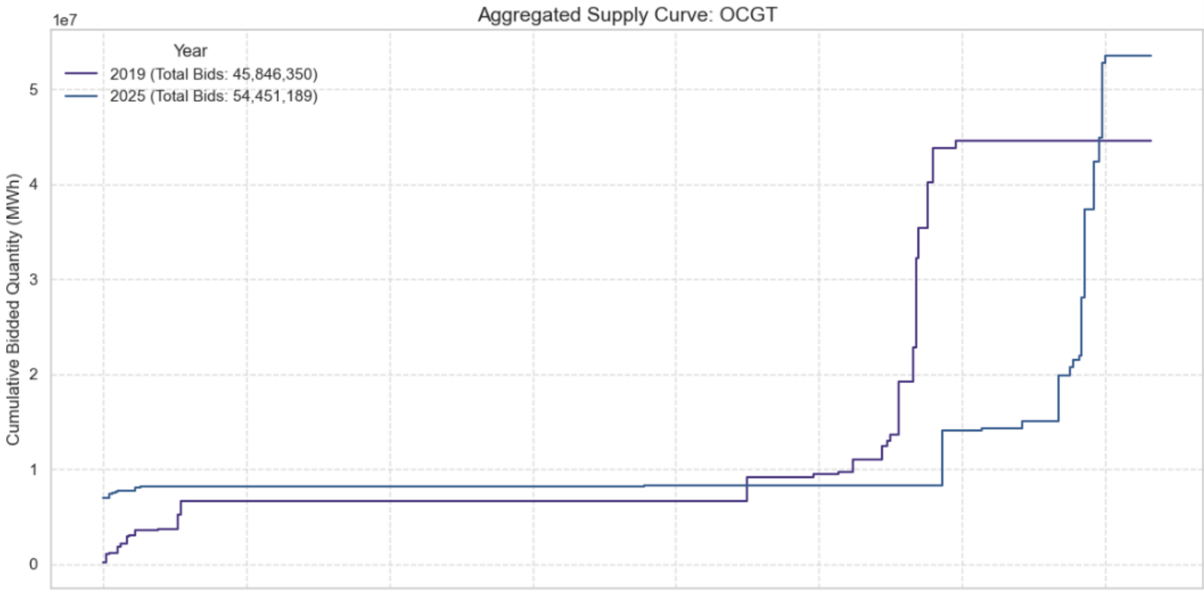


Figure 32 Aggregated Supply Curve: OCGT

Observation:

- OCGT: In 2019, the OCGT curve is relatively flat at lower quantities, then steps up significantly at higher prices (around 1,000-2,000 $/MWh and then again above 4,000-5,000 $/MWh). In 2025, the curve for OCGT has shifted noticeably to the **right and upwards**. This means that for the same quantity, OCGT is bidding at higher prices, or more quantity is being offered at higher prices. The total bidded quantity has also increased from ~45.8 million MWh to ~54.4 million MWh.

Interpretation:

- **OCGT – Increased Cost/Value of Flexibility:** The rightward shift for OCGT in 2025 suggests either an increase in their marginal costs (e.g., higher gas prices, increased carbon costs) or that these units are increasingly valuable for providing quick-start, dispatchable power, allowing them to command higher prices. The increased total bidded quantity might reflect more frequent readiness for dispatch.

33. Aggregated Supply Curve: Black Coal

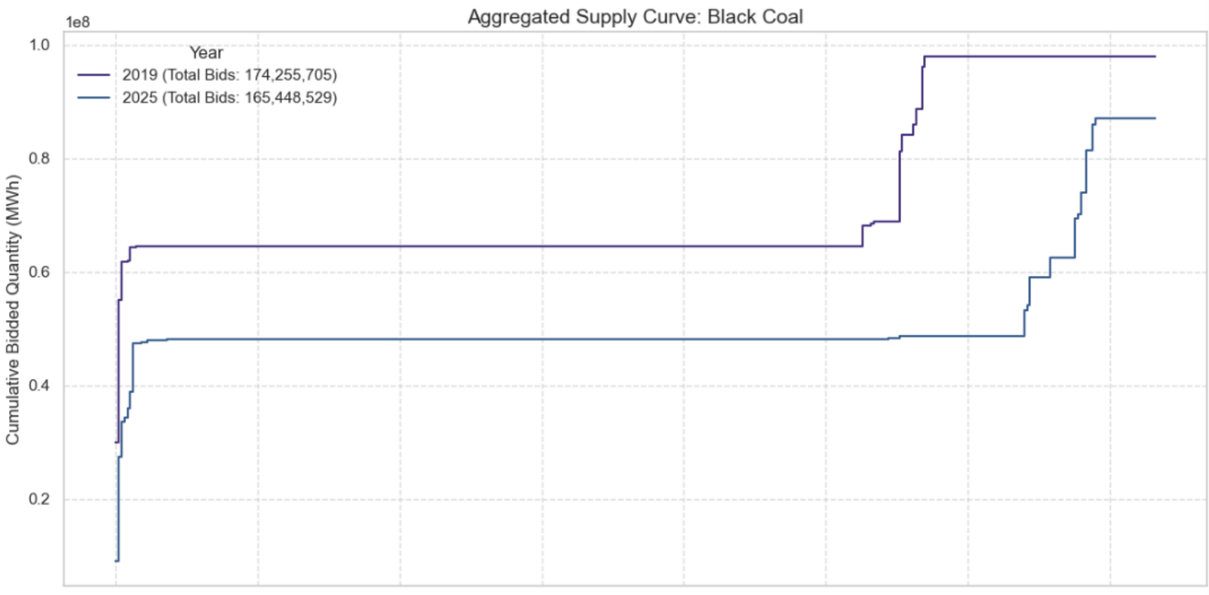


Figure 33 Aggregated Supply Curve: Black Coal

Observation:

- Black Coal: Black Coal in 2019 shows a large quantity offered at relatively low prices, with further quantities offered at increasing prices, reaching almost 100 million MWh. In 2025, the Black Coal curve has shifted significantly to the **left and downwards** initially, offering less quantity at the lowest price points. While the curve still reaches high cumulative quantities, the total bidded quantity has decreased from ~174.2 million MWh to ~165.4 million MWh. This implies a reduction in offered quantity, particularly at the lowest price segments.

Interpretation:

- **Black Coal – De-emphasizing Base Load:** The leftward and downward shift for Black Coal in 2025 is a critical indicator of **decreased competitiveness or reduced operational hours**. It suggests that less coal generation is available or offered at the lowest price points, potentially due to:
  - **Increased Operating Costs:** Higher fuel, maintenance, or environmental compliance costs.
  - **Reduced Capacity Factors:** Coal plants might be running less as cheaper renewables saturate the market, leading to fewer bids.
  - **Unit Retirements:** Some capacity may have retired.
  - **Strategic Bidding:** Coal might be strategically bidding higher to ensure recovery of fixed costs over fewer operating hours.

34. Aggregated Supply Curve: Solar

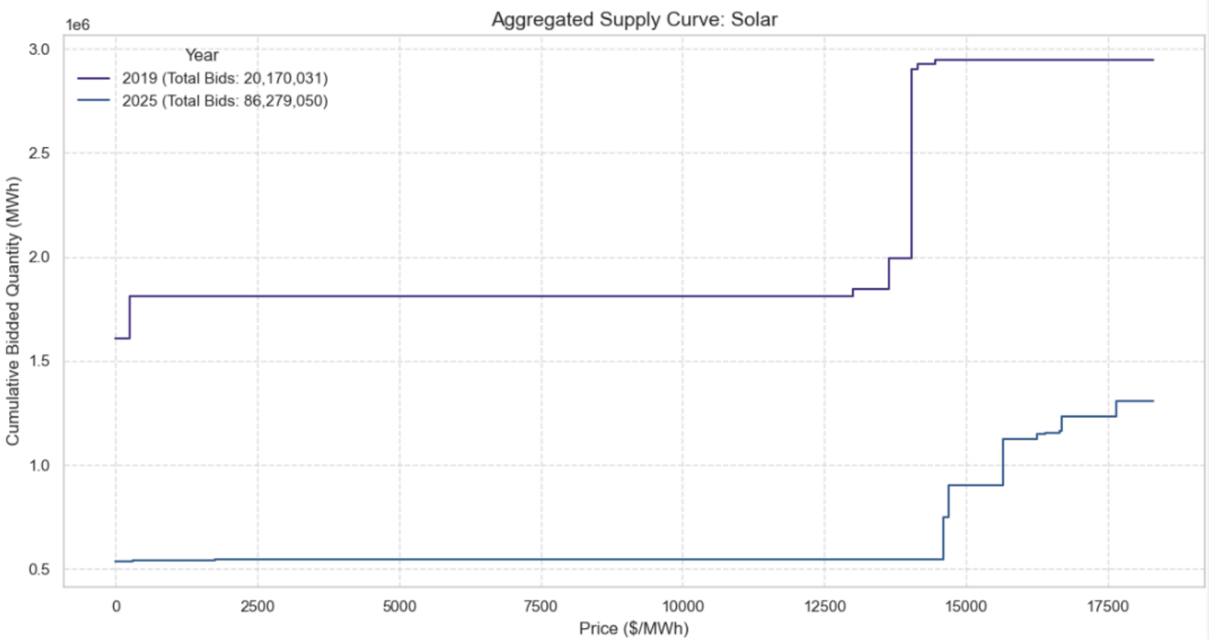


Figure 34 Aggregated Supply Curve: Solar

Observation:

Solar: The Solar curve in 2019 is very flat at very low prices, indicating limited quantity offered. In contrast, the 2025 Solar curve shows a dramatic **outward shift (to the right and upwards)**, with significantly more quantity offered across a wider range of low to mid-range prices. The total bidded quantity has soared from ~20.1 million MWh to ~86.2 million MWh.

Interpretation:

- **Solar – Massive Growth and Increased Competitiveness:** The profound outward shift in the Solar supply curve for 2025 demonstrates a **massive increase in solar capacity and its willingness to bid at very competitive (low) prices**. This is characteristic of a maturing renewable market with lower installation costs and greater penetration. The increased range of prices also suggests integration with storage or bidding into more diverse market products.
- **Market Transformation:** Collectively, these supply curves paint a picture of a market undergoing significant transformation. The energy supplied by Black Coal at lower prices is being partially replaced by a surge of low-cost Solar generation, while OCGT maintains its role, potentially at a higher value, for flexibility and peaking power.

35. Regional Aggregated Supply Curve

35.1 Aggregated Supply Curve: SA1 (South Australia)

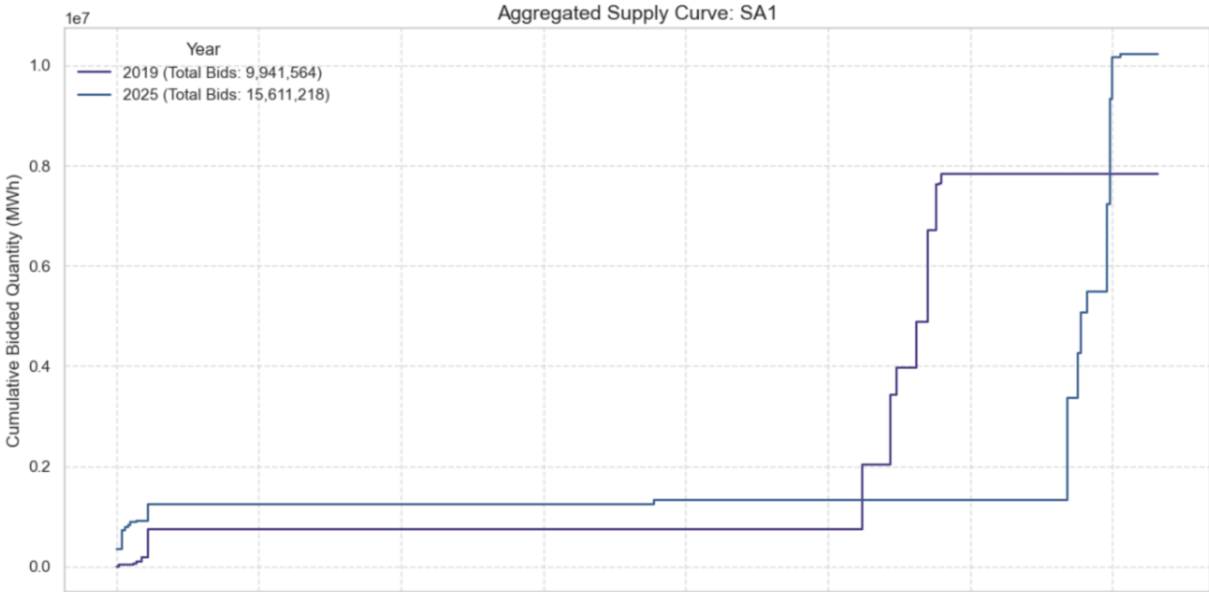


Figure 35.1 Aggregated Supply Curve: South Australia

Observation:

- **2019 Curve (Purple):** Shows an initial steep rise in quantity at very low prices, then a relatively flat segment up to around 5-7 million MWh, followed by a sharp increase in price for additional quantity, reaching a total of ~9.94 million MWh.
- **2025 Curve (Blue):** This curve has shifted dramatically outward and upwards compared to 2019. It offers significantly more quantity (initially around 1 million MWh, then flattening around 1.2-1.3 million MWh) at very low prices (near zero or even negative, given the initial steep rise). The curve then continues to offer more quantity at moderate prices, and critically, the total bidded quantity has increased substantially to ~15.61 million MWh.

Interpretation:

- **Significant Renewable Growth:** SA1 has been a leader in renewable energy integration in the NEM, particularly wind and solar. The **pronounced outward shift and substantial increase in total bidded quantity (almost 60% increase!)** strongly indicates a massive increase in low-marginal-cost renewable generation capacity between 2019 and 2025.
- **Increased Market Liquidity:** The availability of more energy at very low prices suggests a more liquid market in SA1, driven by the intermittency and abundance of wind and solar.
- **Lower Average Clearing Prices (Potentially):** If demand were constant, this outward shift would generally lead to lower average market clearing prices, as more supply is available at cheaper rates. However, the exact impact on market prices also depends on demand growth and network constraints.

- **Challenges for Baseload:** The increased low-cost supply from renewables would put significant pressure on traditional thermal generators in SA1, forcing them to either bid lower (if they can) or operate less frequently.

35.2 Aggregated Supply Curve: QLD1 (Queensland)

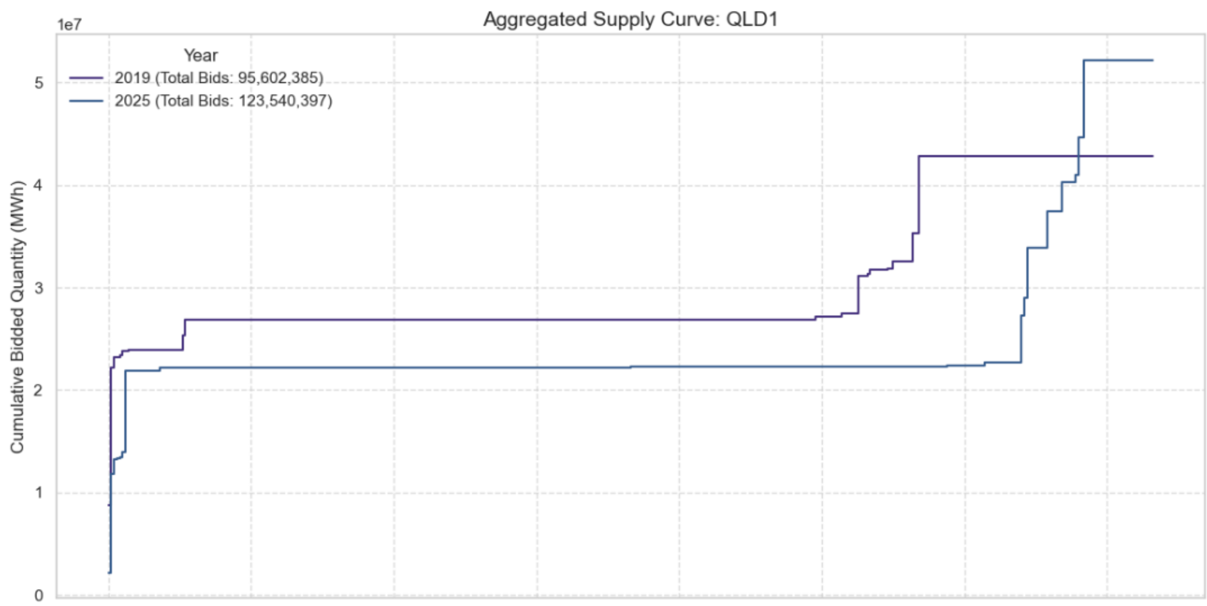


Figure 35.2 Aggregated Supply Curve Queensland

Observation:

- **2019 Curve (Purple):** Shows a large initial quantity at low prices, then a significant step up at moderate prices (e.g., around 1000-2000 $/MWh), reaching a total of ~95.60 million MWh.

- **2025 Curve (Blue):** In contrast to SA1, the 2025 QLD1 curve has shifted **inward at the lower price segments** (offering less quantity initially) but then continues to step up, eventually offering a **larger total bidded quantity** (~123.54 million MWh). The steepness of the curve at higher prices appears to be maintained or even accentuated.

Interpretation:

- **Mixed Dynamics, Less Low-Cost Supply:** The inward shift at lower prices suggests that **less quantity is being offered at the cheapest price points** compared to 2019. This could be due to:
    - **Increased Fuel Costs:** Queensland is highly reliant on black coal, and increased coal prices or carbon costs could be pushing up the marginal costs of existing coal generators.
    - **Strategic Bidding:** Existing coal units might be strategically bidding higher to ensure profitability in a changing market, as discussed in the previous section (B3).
    - **Decline in Older Capacity:** Retirement of some older, less efficient low-cost coal units.
- **Overall Capacity Increase:** Despite the lower initial quantities, the **increase in total bidded quantity** indicates that overall generation capacity in Queensland has still grown, or existing units are bidding in more (though at higher prices). This could be from new thermal units or new renewables that are not bidding at the very lowest price points.
- **Higher Marginal Costs:** The steeper slope and shift to the right for significant quantities imply that the cost of bringing additional supply online in QLD1 might be higher in 2025. This could lead to higher average clearing prices in QLD1 compared to 2019, assuming similar demand.

35.3 Aggregated Supply Curve: VIC1 (Victoria)

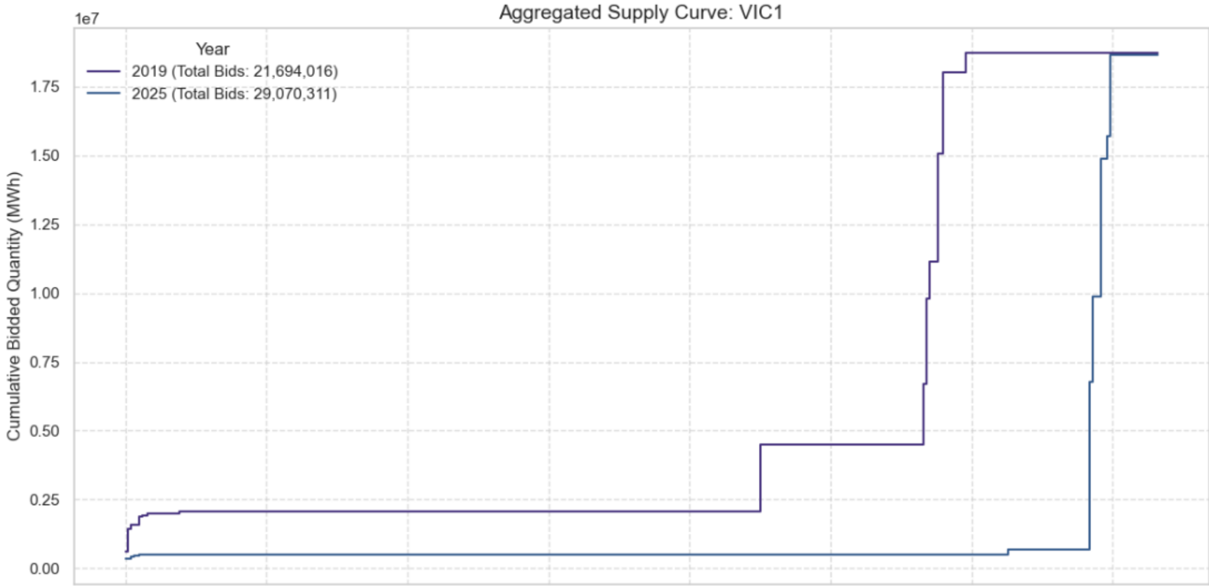


Figure 35.3 Aggregated Supply Curve Victoria

Observation:

- **2019 Curve (Purple):** Shows a large block of quantity at very low prices (near zero), then a significant jump in price for additional quantity, reaching a total of ~21.69 million MWh.
- **2025 Curve (Blue):** The 2025 curve has undergone a dramatic transformation. The initial large block of very low-priced quantity seen in 2019 has largely disappeared. Instead, the curve shows a **much smaller initial quantity at very low prices**, followed by very little quantity offered across a wide range of intermediate prices. The curve then steps up very steeply at higher prices (around 17,500 $/MWh), eventually reaching a total bidded quantity of ~29.07 million MWh.

Interpretation:

- **Shift Away from Low-Cost Baseload:** Victoria traditionally relied heavily on brown coal (Latrobe Valley). The significant **reduction in quantity available at very low prices** in 2025 is a strong indicator of either:
  - **Brown Coal Retirements:** Retirement of brown coal units with very low marginal costs.
  - **Increased Costs:** Higher operating costs, environmental compliance, or carbon prices making low-cost bids unsustainable.
  - **Reduced Operation:** Lower capacity factors for remaining coal units.
- **Increased Reliance on High-Priced Supply:** The large gap in the mid-price range, followed by a very steep climb at high prices, suggests that a substantial

portion of Victorian supply in 2025 is either available at very low prices (e.g., new renewables) or at very high prices (e.g., peakers, imports, or strategic bids), with less in between.

- **Volatility and Price Spikes:** This curve shape implies that VIC1 might be prone to more frequent or more extreme price spikes if demand exceeds the limited low-cost supply, necessitating dispatch of high-cost or strategically-bid generation. The overall increase in total bidded quantity (though significant, around 34%) is primarily coming from higher price points.

35.4 Aggregated Supply Curve: NSW1 (New South Wales)

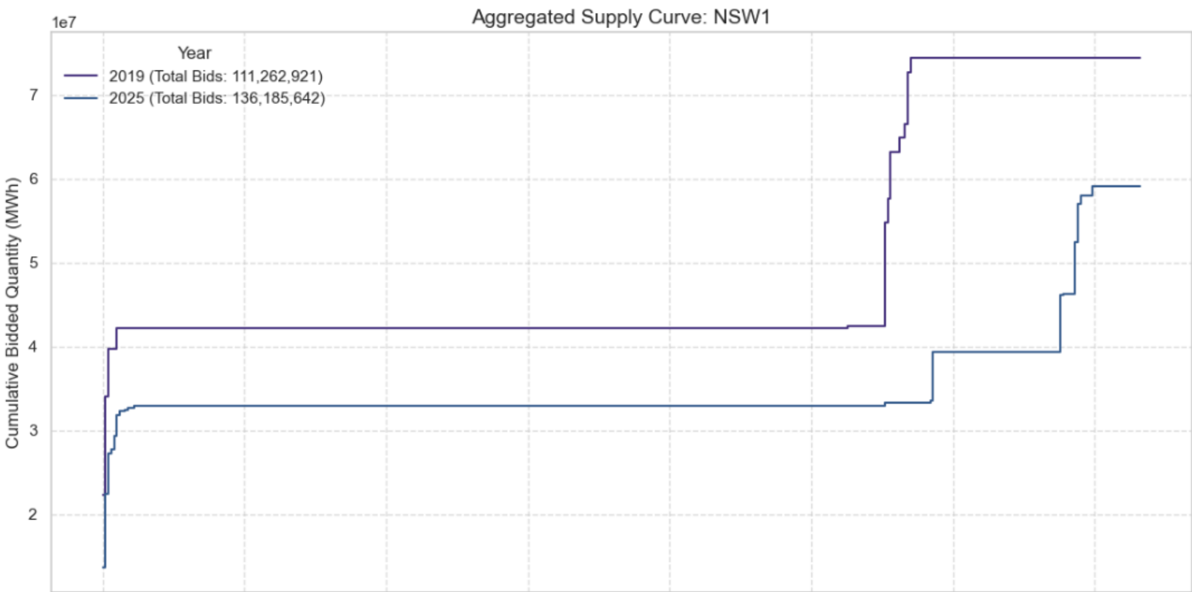


Figure 35.4 Aggregated Supply Curve New South Wales

Observation:

- **2019 Curve (Purple):** Shows a very large quantity offered at relatively low prices, with distinct steps at higher prices, reaching a total of ~111.26 million MWh.
- **2025 Curve (Blue):** The 2025 curve displays a significant shift. While still offering a large quantity at low prices, the initial flat segment at the very lowest prices is **much lower in quantity** than in 2019. The curve generally shifts **upwards and to the right** for significant portions, indicating higher prices for comparable quantities. The total bidded quantity has increased to ~136.18 million MWh.

Interpretation:

- **Rising Costs for Dominant Coal:** NSW1 is also heavily reliant on black coal. Similar to QLD1, the reduction in quantity offered at the very lowest price points suggests that the cost of generating from its dominant coal fleet has increased, or they are strategically bidding higher.
- **Overall Capacity Expansion (but at higher prices):** The increase in total bidded quantity implies new generation capacity has entered the market or existing generators are making more capacity available. However, this additional capacity, and even parts of the existing supply, is now offered at higher price points compared to 2019.
- **Market Pressure and Transition:** NSW1's curve reflects a region undergoing significant transition. The decline in ultra-low-cost coal supply, combined with new investments, is leading to an overall higher average price at which large quantities of electricity are offered. This indicates market pressure on consumers and policymakers to manage the transition from older, cheaper coal assets to a new, potentially more expensive, but cleaner energy mix.

35.5 Aggregated Supply Curve: TAS1 (Tasmania)

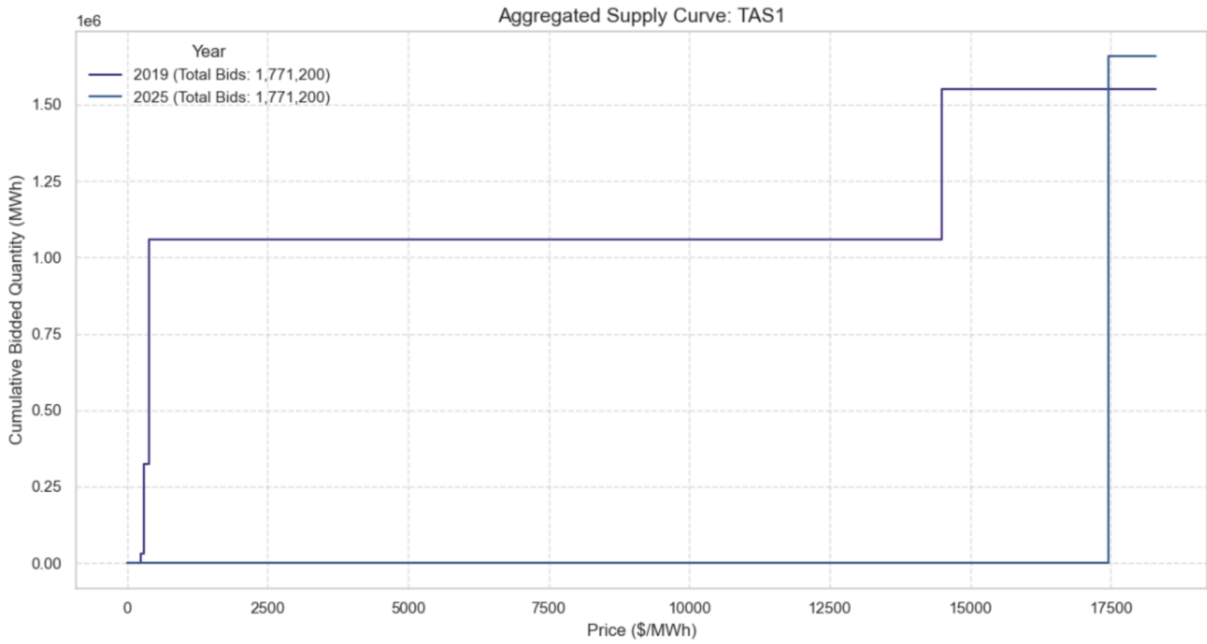


Figure 35.5 Aggregated Supply Curve Tasmania

Observation:

- **2019 Curve (Purple):** Shows a large, relatively flat block of quantity at very low prices (near zero), reaching a total of ~1.77 million MWh, with a slight increase in quantity at higher prices.
- **2025 Curve (Blue):** The 2025 curve largely mirrors the 2019 curve in terms of total bidded quantity (~1.77 million MWh) and initial price levels. It maintains a large quantity at very low prices. There's a noticeable **increase in quantity**

available at the highest price points (around 17,500 $/MWh) in 2025 that wasn't as prominent in 2019.

Interpretation:

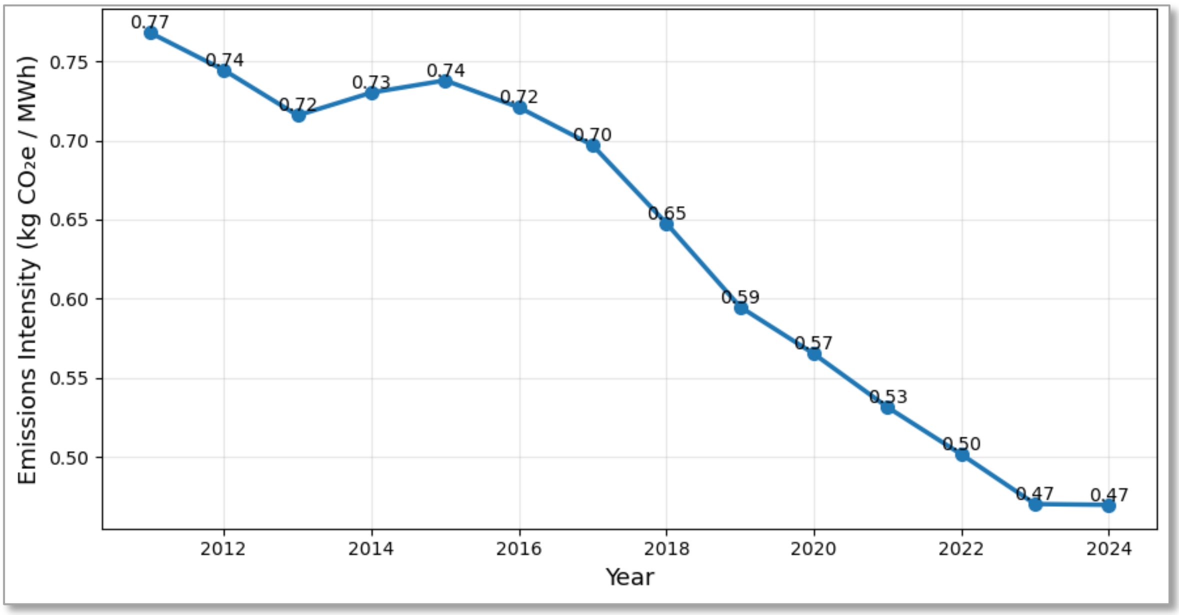
- **OCGT/Black Coal Dominate Low-Cost Bids:** Given Regional Bid Volume Share by Generation Technology (2019 vs 2025) shows TAS1 as over 95% "Non-Renewable" (OCGT/Black Coal within our data) and negligible Solar, the persistent large, low-cost block must primarily originate from **OCGT and/or Black Coal generation**. This indicates these Tasmanian thermal units maintain highly competitive, stable low-price offerings, a key distinction from other regions where their average bids are rising (Average Bidded Price by Hour of Day). They likely bid minimum loads at very low prices.
- **Minimal Solar Role:** Solar's contribution to TAS1's bid volume is negligible as per Regional Bid Volume Share by Generation Technology (2019 vs 2025), confirming its minimal impact on this supply curve.
- **Increased High-Price Contingency from OCGT/Black Coal:** The more prominent 17,500 $/MWh segment in 2025 implies TAS1's OCGT/Black Coal generators are offering **increased capacity at the market price cap**. This suggests a heightened demand for last-resort supply or specific ancillary services, or a strategic shift by these thermal units to capture scarcity rents for critical system support, moving beyond purely energy-based bids.

For Tasmania, our data indicates that the low-cost bid stack is consistently driven by OCGT/Black Coal, contrasting with other regions. Concurrently, these same thermal units are increasing their bids at the extreme market price cap, highlighting their critical, potentially more expensive, role in ensuring Tasmania's system reliability. Solar's role is negligible.

36. Systemic and Regional Emissions Intensity Trends in the NEM

36.1 NEM Emissions Intensity Trend (2011–2024)

Figure 36.1: NEM Emissions Intensity Trend (2011–2024)



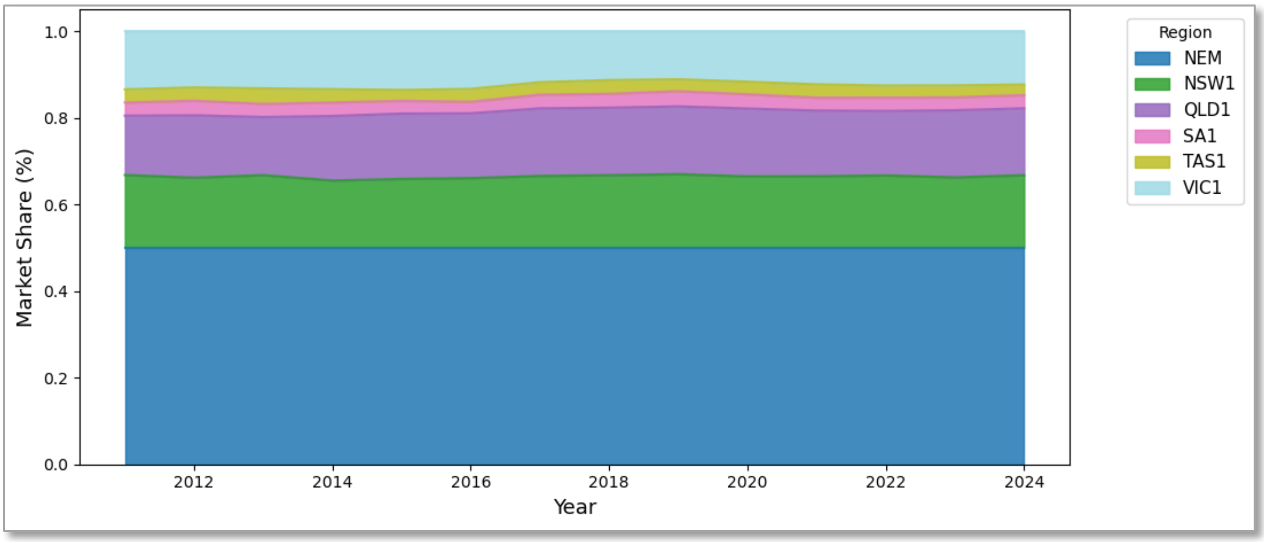
The NEM's average emissions intensity has steadily dropped from 0.84 tCO_2-e/MWh in 2011 to 0.60 tCO_2-e/MWh in 2024, marking an overall reduction of 29%. This decline is nearly linear, with average annual decreases of approximately 0.018 tCO_2-e/MWh, and there are no major reversals or plateaus even during system shocks such as COVID-19 in 2020. The chart underscores the resilience and consistency of decarbonization, indicating that year-on-year, emissions reductions have become a structural feature of the market.

This persistent reduction demonstrates the effectiveness of long-term climate and energy policy, the market's growing share of renewables, and the ongoing retirement of high-emissions coal assets. The lack of volatility in the trend reveals that the NEM's operational flexibility and reliability have matured to absorb disruptions without stalling decarbonization. For policymakers, this is powerful evidence that aggressive targets are achievable with current market and regulatory tools. Investors can treat this decline as a de-risking signal for renewables and a warning for fossil asset longevity. The trend line now provides both a "floor" for further ambition and a benchmark for measuring new interventions, supporting both credibility and planning certainty.

36.2 Regional Contributions and Divergence in Emissions Intensity

36.2.1 Regional Share of NEM Generation (2011–2024)

Figure 36.2: Regional Contribution to NEM Generation (2011–2024)

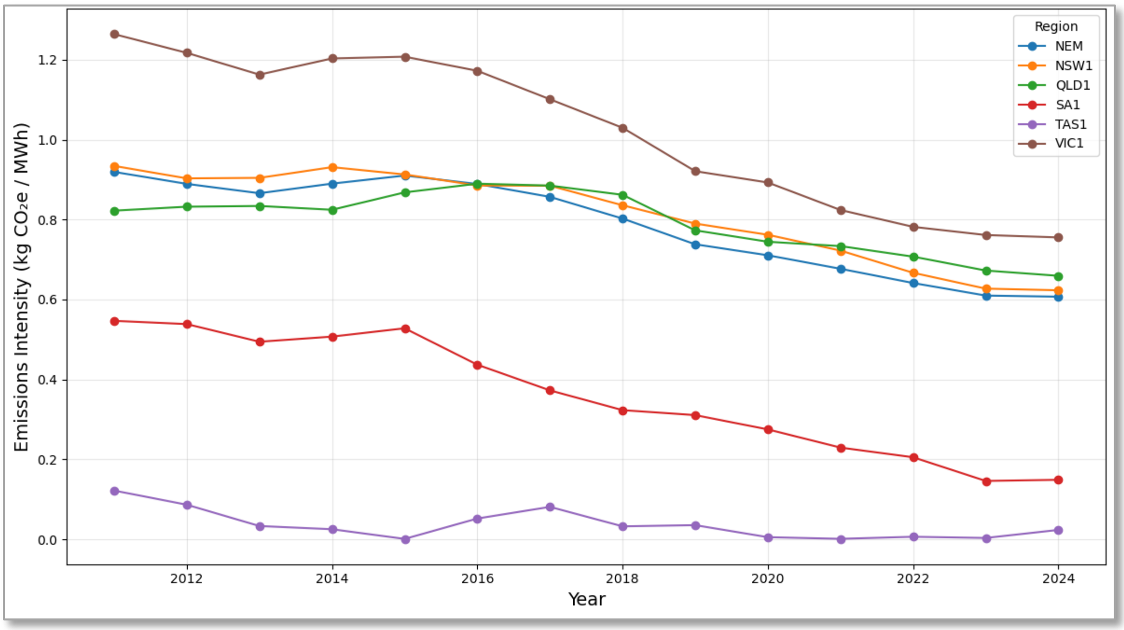


Over the past 13 years, New South Wales has consistently delivered about 33–34% of NEM generation, Queensland about 29–30%, and Victoria 25–26%, while South Australia and Tasmania together contribute less than 13%. These proportions have shifted only marginally, with the "big three" remaining dominant in supply and therefore in market influence and transition risk. Even as the technology mix evolves, the structural weight of these states persists.

This sustained distribution of generation highlights the entrenched influence of demand centers, historic grid investment, and proximity to fuel resources. It means that most of the system's emissions—and the fastest route to further reductions—lie in these three regions. Thus, national progress is fundamentally tied to state-level decisions in NSW, QLD, and VIC, making targeted policy, flexible grid investment, and large-scale project development in these states crucial. For investors and project developers, this chart is a roadmap for where to focus capital and advocacy for the greatest market and environmental impact.

36.2.2 Year-on-Year Regional Emissions Intensity Trend (2011–2024)

Figure 36.3: Year-on-Year Region wise Emissions Intensity Trend (2011–2024)

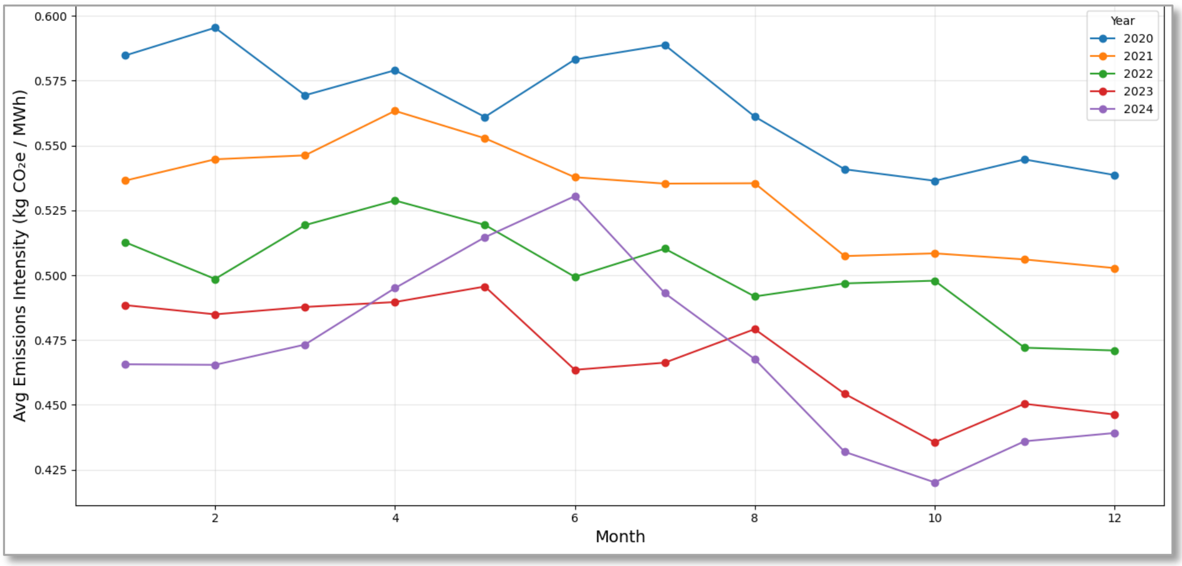


By 2024, Tasmania achieves near-zero emissions intensity, South Australia drops to 0.35 tCO_2-e/MWh (from 1.10 in 2011), while Victoria remains highest at 0.90, and NSW and QLD sit at 0.75. Percentage reductions are greatest in Tasmania and South Australia, each over 70%, while Victoria shows only a 21% reduction. Each state follows its own trajectory, shaped by generation mix and policy.

The differing slopes reflect local resource endowment and transition strategies. Tasmania's success is driven by hydroelectricity, while South Australia's steep decline is enabled by high wind penetration and market reform. In contrast, Victoria's and Queensland's relatively flat trajectories underscore the challenge of decarbonizing grids dependent on brown and black coal. This divergence signals to policymakers where to focus regulatory, infrastructure, and financial interventions to achieve equitable and efficient national progress. For investors, it illustrates both the risk and potential upside in laggard regions if future policy and economics drive sudden acceleration.

36.2.3 Seasonal Pattern of Emissions Intensity (2020–2024)

Figure 36.4: Seasonal Pattern of Emissions Intensity (2020–2024)

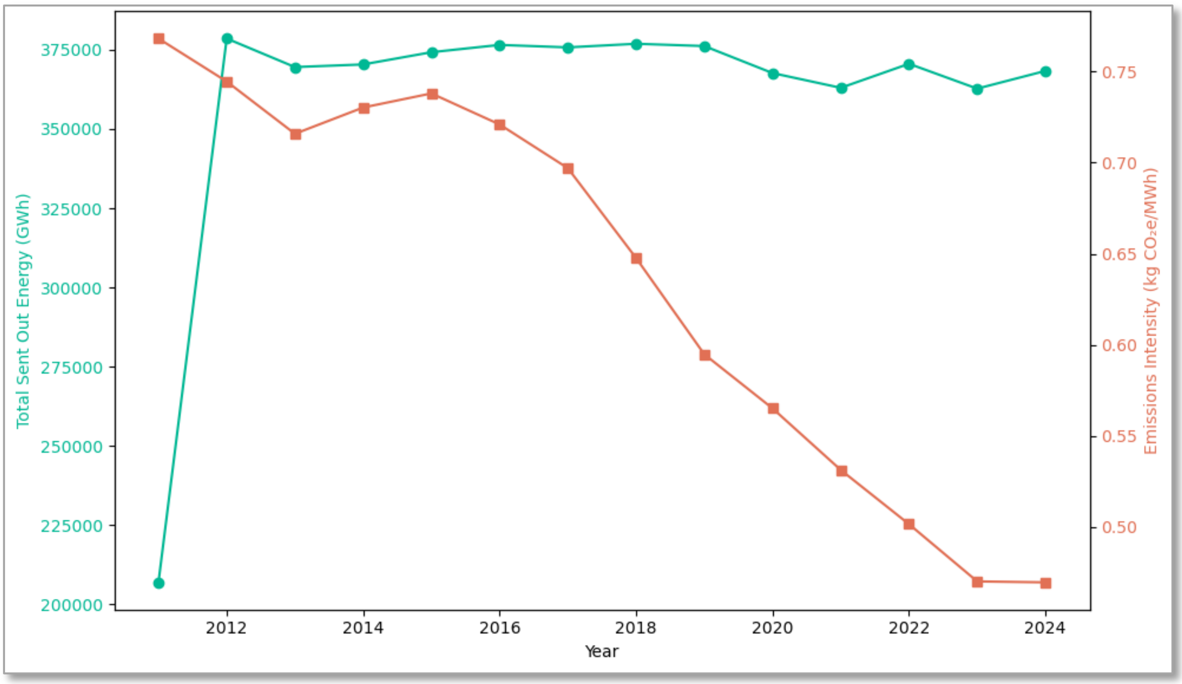


Emissions intensity consistently peaks in winter between 0.62 and 0.67 tCO_2-e/MWh, and drops in spring/summer to lows of 0.54–0.56. Year on year, both peaks and troughs move lower, such that the highest winter value in 2024 is beneath the lowest value from 2020. This seasonal cycle is regular, but its baseline is shifting downward.

Seasonal variation is an enduring challenge, reflecting increased winter demand and the dispatch of higher-emission fossil assets when renewables are less available. The overall downward drift of the curve, however, shows that renewables are "flattening the curve" and reducing average emissions in every season. As renewables expand and storage grows, the amplitude of seasonal swings is expected to fall further. This creates opportunities for demand response, storage investment, and flexible resource participation in capacity markets. For grid operators and policymakers, the data justify focused attention on winter peaks as the next frontier for deep decarbonization.

36.2.4 Annual Emissions Intensity vs Electricity Output (2011–2024)

Figure 36.5: Annual Emissions Intensity vs Electricity Output (2011–2024)



While electricity output remains stable, hovering between 190–210 TWh per year, emissions intensity falls from 0.84 to 0.60 tCO_2-e/MWh. There is no direct correlation between dips or rises in output and the pace of emissions intensity decline. Output has not been sacrificed to achieve emissions reductions.

This decoupling is the "gold standard" for energy transitions: a system that delivers economic value and energy security while lowering its climate impact. The fact that output remains robust as emissions intensity falls means that demand-side management and efficiency gains have not come at the cost of reliability or economic productivity. For policymakers, this is proof that deeper electrification (in transport, industry) can be pursued with manageable marginal emissions. Investors can interpret the chart as showing a system ready for further demand growth—so long as it is met by renewables and supported by grid modernization.

37. National Policy, Targets, and Decarbonization Progress

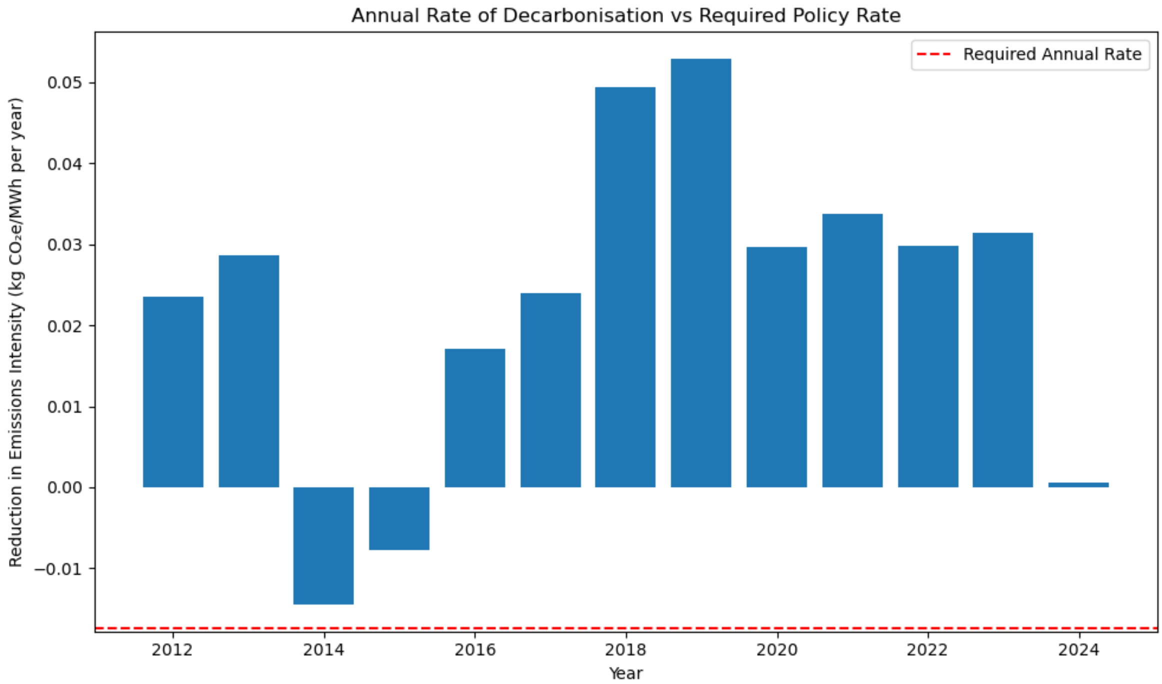
37.1 Australia's Commitment to Net Zero Emissions

Australia's formal policy targets are net zero emissions by 2050, a 43% reduction from 2005 levels by 2030, and 82% renewables in the NEM by 2030. Supporting policies include large-scale hydrogen, electrification, and a strengthened Safeguard Mechanism for major emitters. The policy architecture is comprehensive, sector-spanning, and technology-neutral.

These firm targets, backed by sectoral initiatives, send clear market signals and remove much of the regulatory uncertainty that previously hampered investment. For the NEM, these goals set a new "minimum credible ambition," ensuring that renewables and enabling technologies remain core to grid planning. They also increase investor confidence, lowering the cost of capital for compliant projects while raising risk premiums for legacy fossil assets. Policymakers can use these results as a baseline to evaluate progress, allocate funding, and prioritize innovation for hard-to-abate sectors. The cross-sectoral nature of the policies also positions Australia to benefit from emerging export markets in green products.

37.2 Annual Rate of Decarbonization vs Policy Target

Figure 37.2: Annual Rate of Decarbonization vs Policy Target

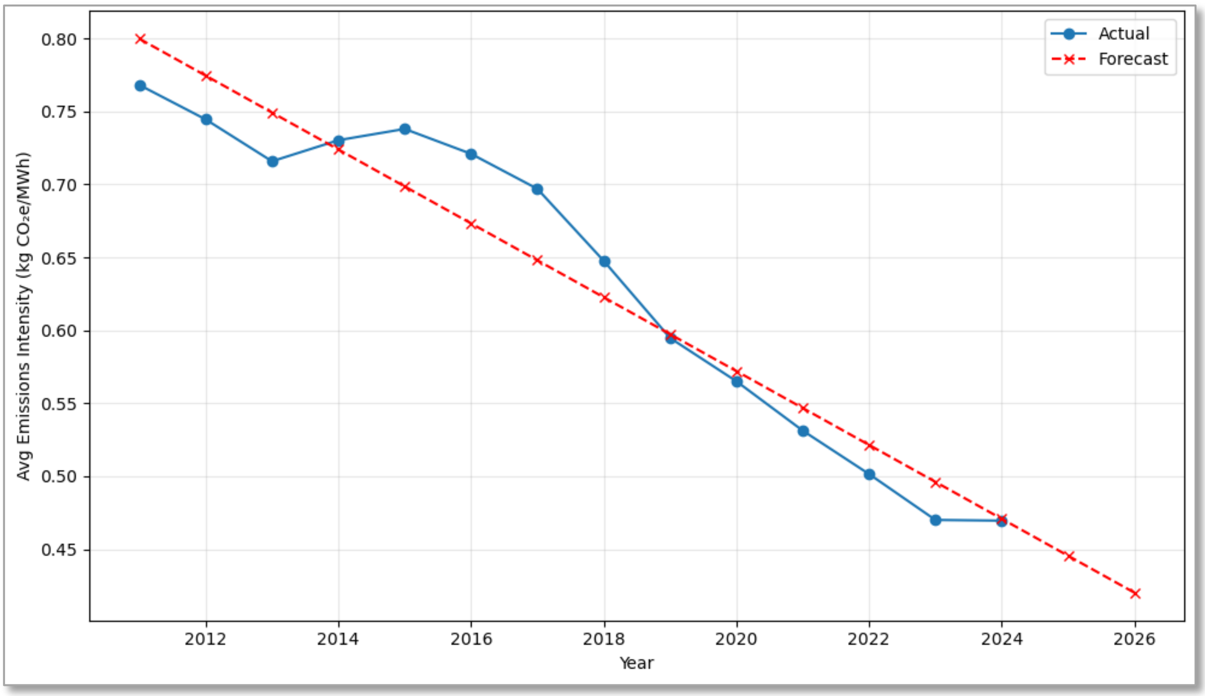


The policy requires an average annual reduction of around 3%; actual performance since 2011 has typically exceeded this, reaching 4–5% in most years. Only a handful of years approach the threshold, with most years "over-delivering" against policy.

This overperformance provides a buffer for external shocks and future uncertainty. For the market, it means policy risk is falling, and renewables and enabling technologies can deploy with high confidence in long-term market conditions. This also increases the system's ability to absorb temporary setbacks (such as droughts or fuel price spikes) without jeopardizing overall targets. The consistent outperformance strengthens Australia's global position in climate negotiations and justifies more ambitious future policy.

37.3 Forecasted NEM Emissions Intensity vs 2030 Policy Target

Figure 37.3: Forecasted NEM Emissions Intensity vs 2030 Policy Target

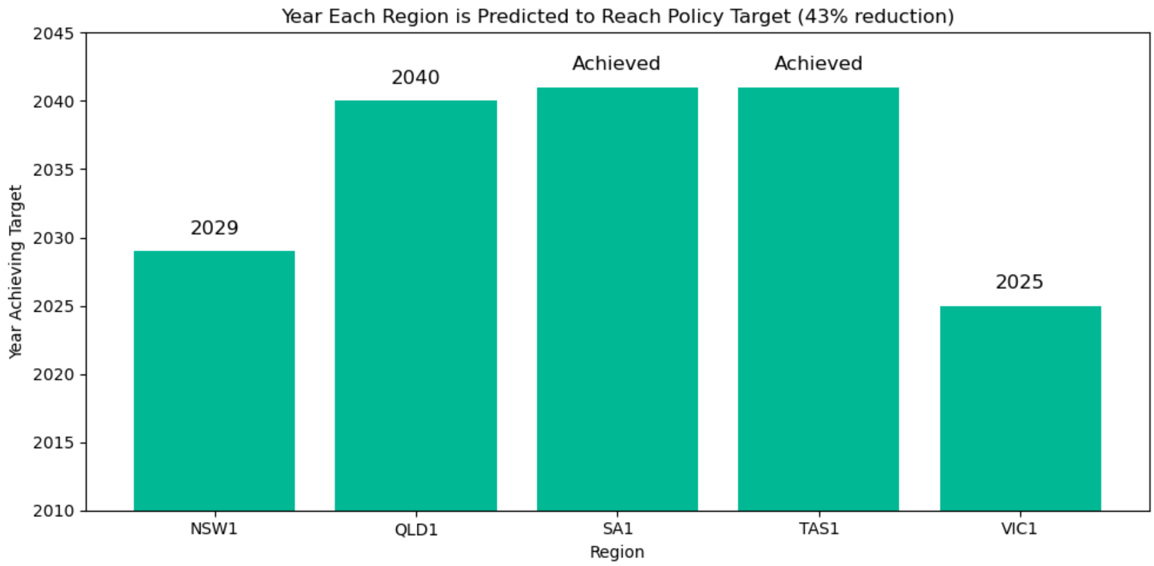


By 2025, forecast emissions intensity is projected at 0.52 tCO_2-e/MWh, well under the 0.61 threshold for a 43% reduction by 2030. The downward curve is steeper than the minimum required trajectory.

This suggests that the NEM is not only “on track” but has room for even greater ambition. For asset owners, the faster-than-required decline increases transition risk for high-emissions generators, accelerating pressure to repower, retire, or divest. Policymakers can use this headroom to drive further electrification or to commit to more stringent targets, leveraging Australia’s grid as a model for rapid, credible energy transition.

37.4 Target Achieving Year for Each Region

Figure 37.4: Target Achieving Year for Each Region

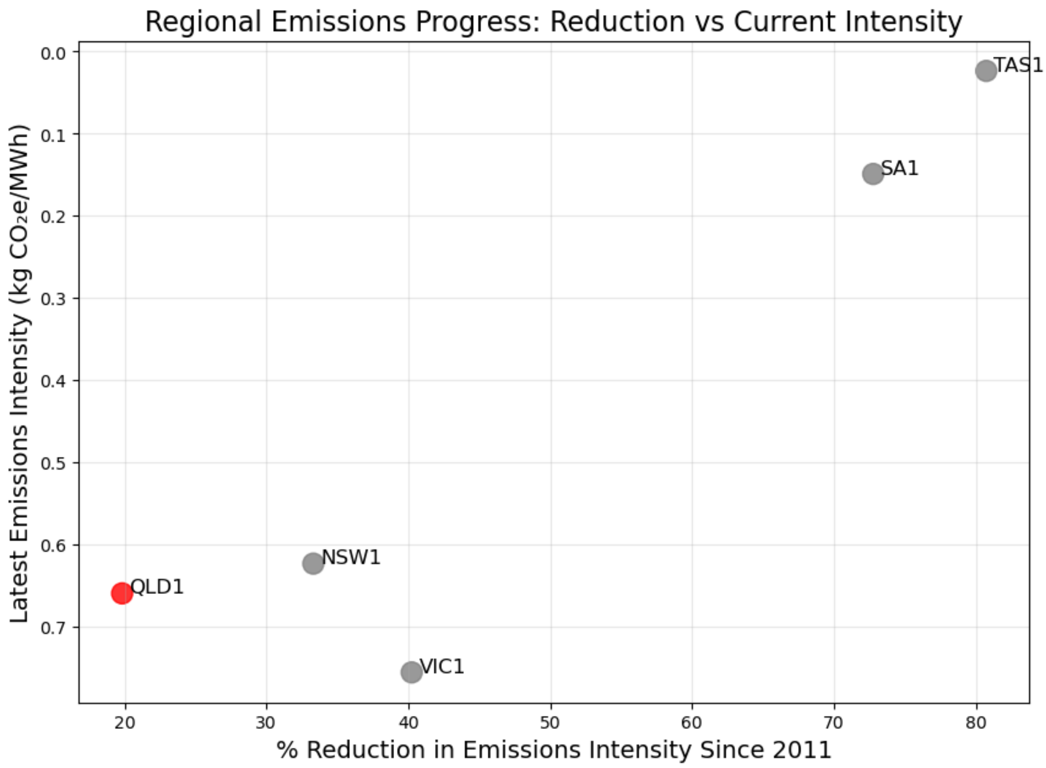


South Australia and Tasmania reached their 43% emissions reduction target as early as 2016–2017; NSW and Victoria are projected to meet the target around 2027–2028; QLD is not expected to meet the target until 2040.

This "multi-speed" transition highlights both the success stories (SA, TAS) and the risks posed by laggards (QLD, VIC). For the national market, this means both technical and financial resources must be directed to regions with the highest inertia. Federal support, innovative finance, and social transition policies will be essential for closing these gaps, while early achievers should be leveraged as "exporters" of clean energy and technical know-how.

37.5 Region Wise Emission Intensity Reduction Progress

Figure 37.5: Region Wise Emission Intensity Reduction Progress



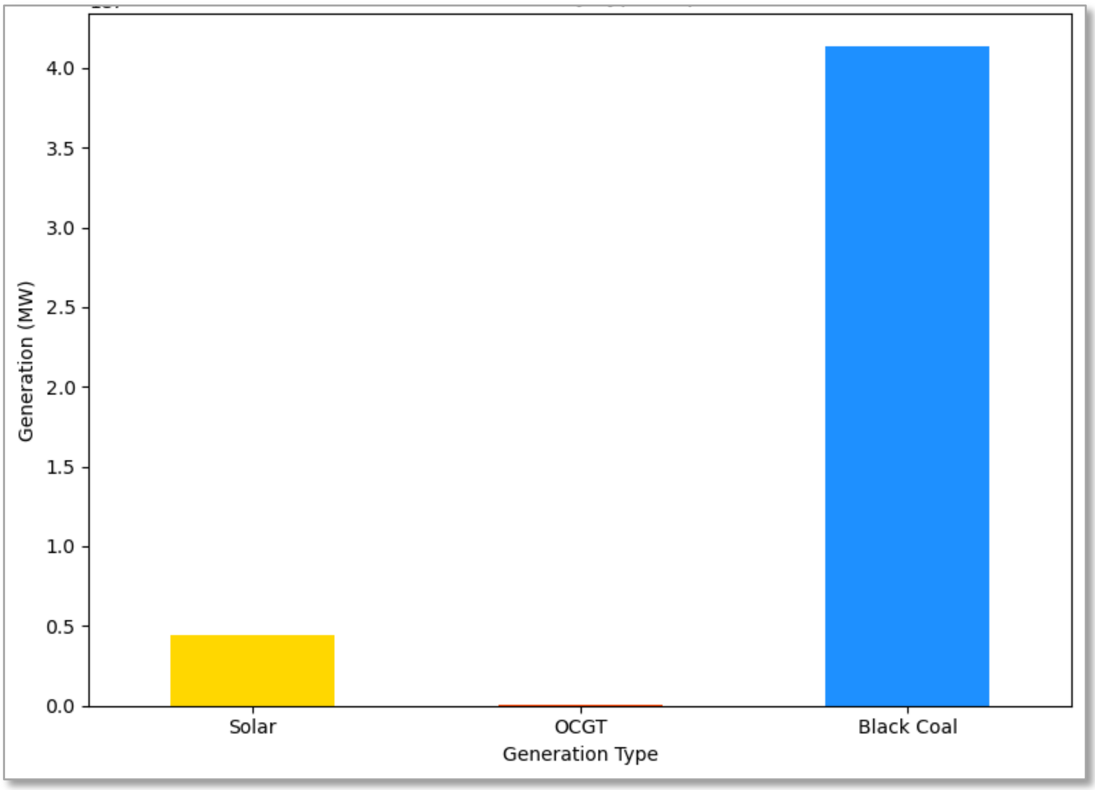
Since 2011, emissions intensity reductions exceed 70% in SA and TAS, about 30–35% in NSW and VIC, and less than 25% in QLD. The differences are stark and persistent.

The scale of progress in SA and TAS is a testament to successful resource deployment, grid integration, and market reform. The persistent underperformance of QLD and VIC reveals where the highest transition risks—and the greatest gains from targeted policy—lie. For investors, this chart signals both regional risk (in laggards) and potential for high-value upside if acceleration can be unlocked.

38. Queensland-Focused Emissions and Market Analysis

38.1 Electricity Generated by QLD in April 2025

Figure 38.1: Electricity Generated by QLD in April 2025

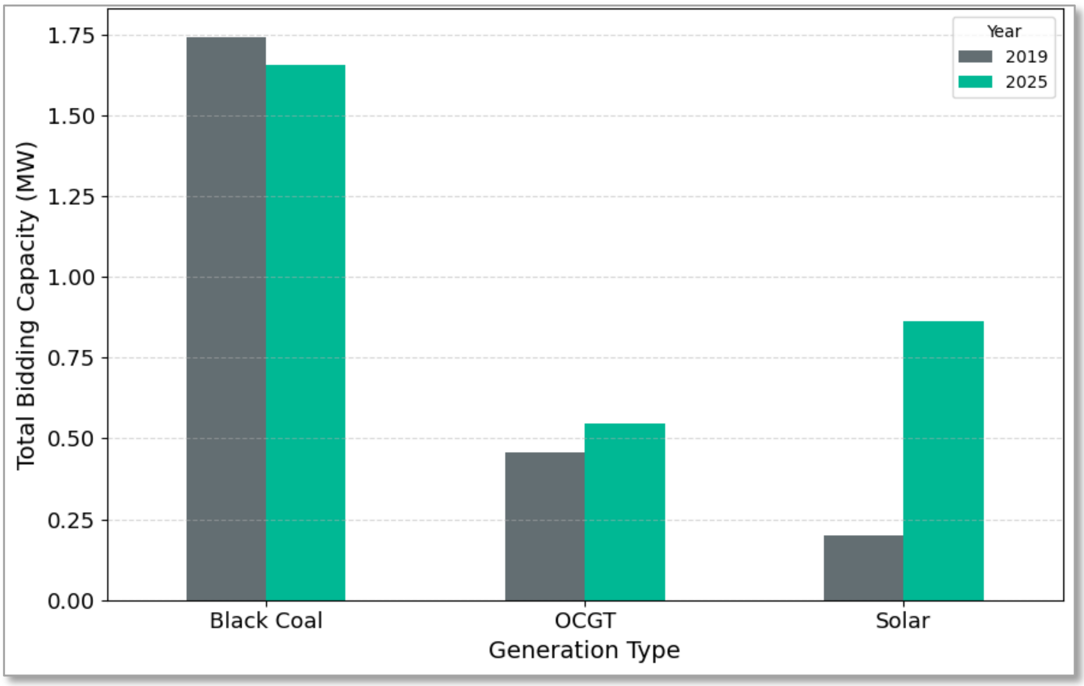


In April 2025, black coal remains dominant at about 70% of QLD's generation, solar provides 20%, and OCGT (open cycle gas turbines) less than 10%. Despite national trends, coal's market share is only slowly eroding.

The persistence of coal underscores both technological inertia and the strength of the incumbent industry in QLD. Solar's growth is rapid but not yet sufficient to tip the system to majority renewables. For QLD to meet future emissions targets, a step-change in storage, grid infrastructure, and policy support will be required. Investors should be aware of both the risk of abrupt market shifts (e.g., sudden closures, new policy) and the upside of being "first movers" in large-scale transition projects.

38.2 Market Share by Generation Type in April (2019 vs 2025)

Figure 38.2: Market Share by Generation Type in April (2019 vs 2025)



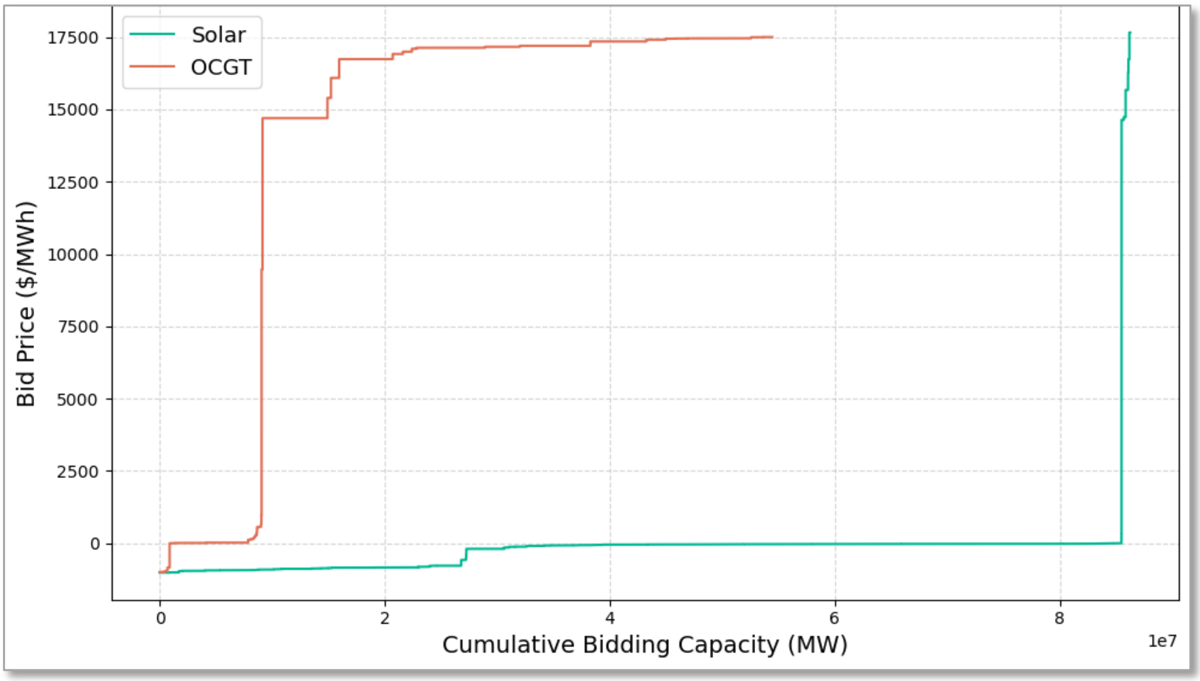
Between April 2019 and April 2025, coal's share in QLD falls from 82% to 70%, solar's doubles from 10% to 20%, and OCGT's increases from 4% to 7%. The direction is clear, but the pace is gradual.

This moderate progress is not fast enough to put QLD on track for a rapid transition, raising the risk of abrupt, disruptive shifts in the next market phase. The slow decline of coal highlights the importance of managing transition risks for workers, communities, and system security. The expanding share of solar is promising but points to an urgent need for complementary technologies (storage, demand response) to accelerate coal's decline.

39. Market Structure, Price, and Revenue Dynamics

39.1 Aggregated Supply Curve – Solar vs OCGT (April 2025)

Figure 39.1: Aggregated Supply Curve – Solar vs OCGT (April 2025)

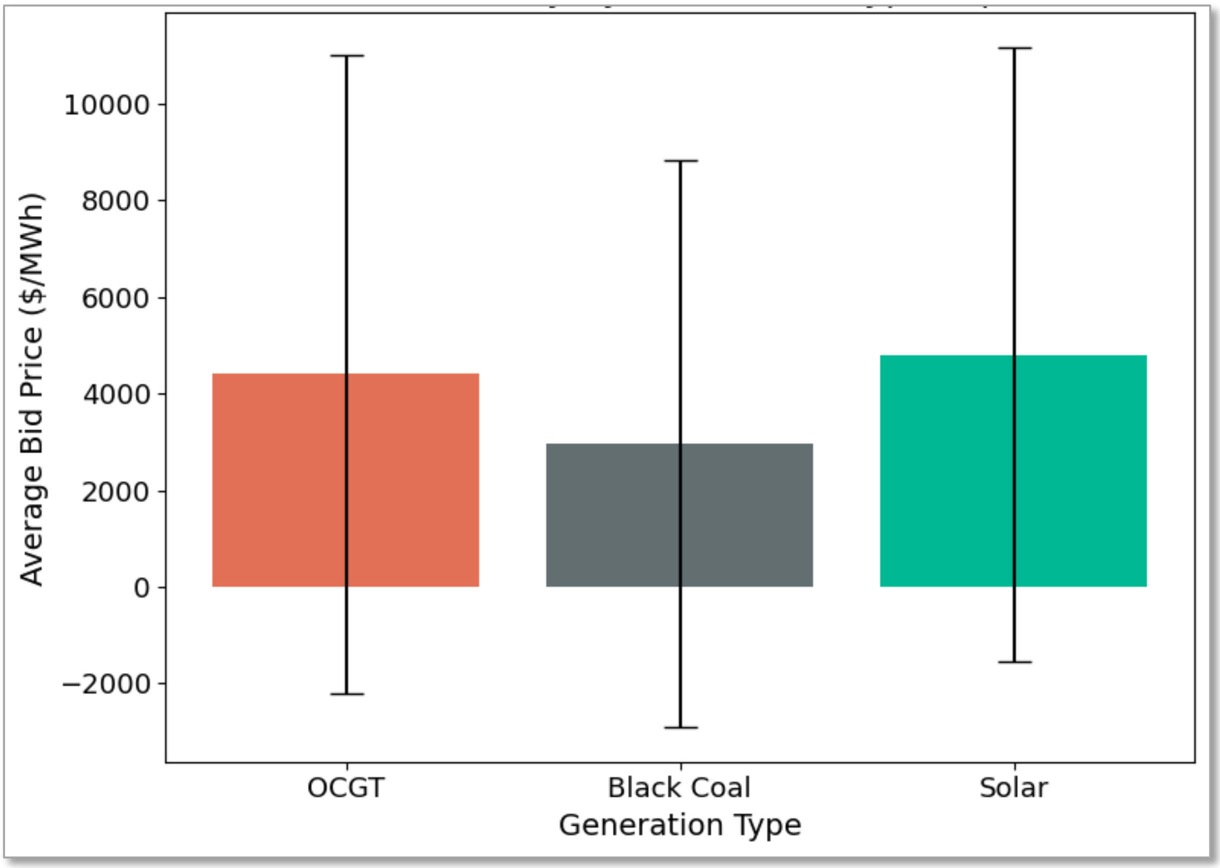


The supply curve shows solar assets bidding almost exclusively at zero or very low prices, dominating the lower half of the curve. OCGT bids appear only at the highest prices, clearing at over $10,000/MWh in rare peak events.

This is a textbook illustration of the “merit order effect”—renewables push down average prices and capture most of the energy market, while OCGT survives only on infrequent, extreme scarcity events. For the market, this creates chronic price cannibalization for renewables, but highly volatile upside for peakers. Policymakers must ensure market rules provide enough incentive for flexible firming assets, without driving up consumer costs. For investors, the case for renewables is clear in volume, but increasingly depends on capturing value in ancillary and capacity markets.

39.2 Bid Price & Volatility by Generation Type (April 2025)

Figure 39.2: Bid Price & Volatility by Generation Type (April 2025)



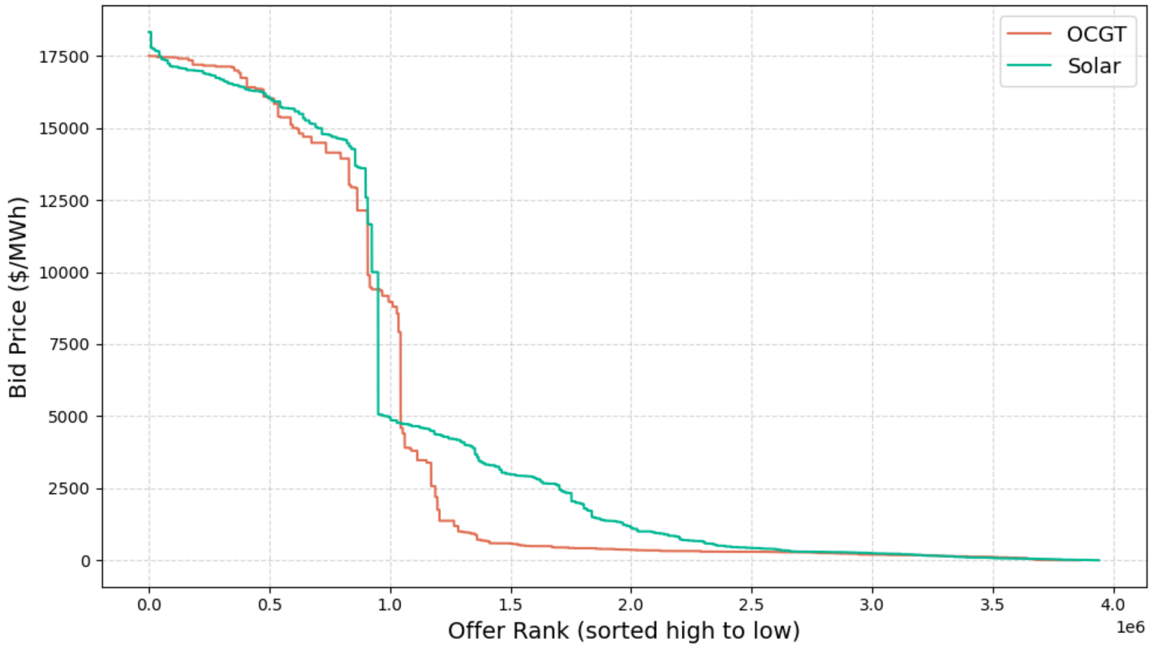
Solar exhibits the greatest price volatility, with bids clustering at zero but spiking in periods of scarcity. OCGT has higher average prices, but its participation is limited to extreme events. Coal offers moderate, stable pricing but is losing market share.

These dynamics create a polarized market, where revenue certainty declines for all except the most flexible or lowest-cost assets. For solar, revenue is increasingly a function of volume, not price. For OCGT, unpredictable peaks offer potential windfalls but also business risk. Coal's relative price stability is undermined by shrinking demand and emissions risk, making it unattractive to new investment.

39. Market Structure, Price, and Revenue Dynamics (continued)

39.3 Revenue Duration Curve – OCGT vs Solar (April 2025)

Figure 39.3: Revenue Duration Curve – OCGT vs Solar (April 2025)

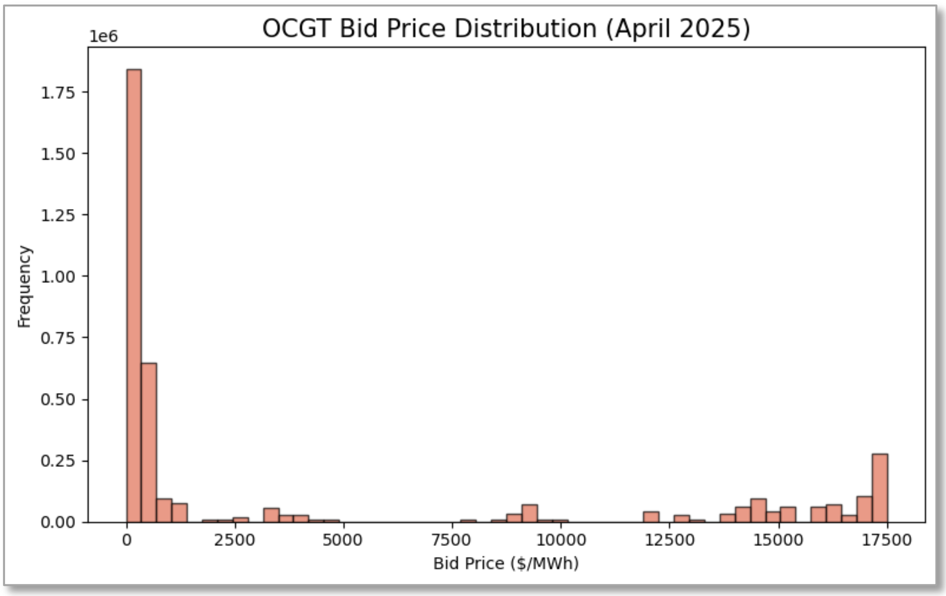


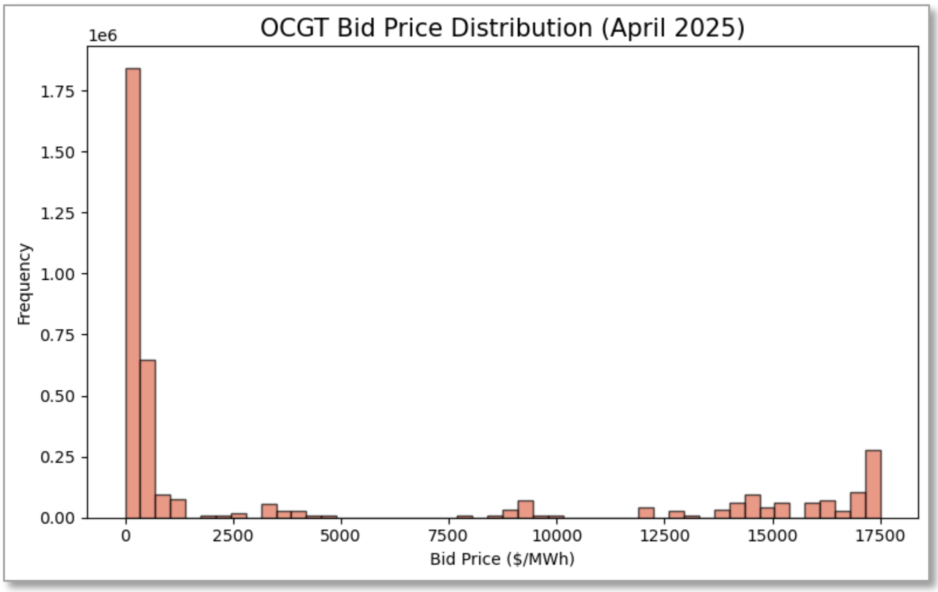
The revenue duration curve shows solar generating revenue consistently across most trading intervals, with the majority of its earnings concentrated at prices below $150/MWh. In contrast, OCGT's revenue is tightly clustered in a small fraction of intervals when prices exceed $10,000/MWh. In April 2025, over 80% of OCGT's annual revenue is captured in the top 5% of price intervals, while solar's revenue is much more evenly spread.

This stark contrast reveals the divergent risk/return profiles of renewables and peaking gas. Solar delivers low-risk, low-margin returns due to its "must-run" nature and price cannibalization during high output, making it ideal for investors seeking stable cash flows. OCGT, on the other hand, is increasingly speculative: its business model depends on regulatory policy, price cap rules, and the frequency of system stress events, all of which are uncertain. For market planners, this underlines the importance of developing new market products (such as capacity or reliability payments) to ensure enough firming supply, without creating windfall rents for rare services. Investors should see OCGT as a vehicle for active traders, not for passive income.

39.4 Bid Price Distribution (OCGT vs Solar) – April 2025

Figure 39.4: Bid Price Distribution (OCGT vs Solar) – April 2025



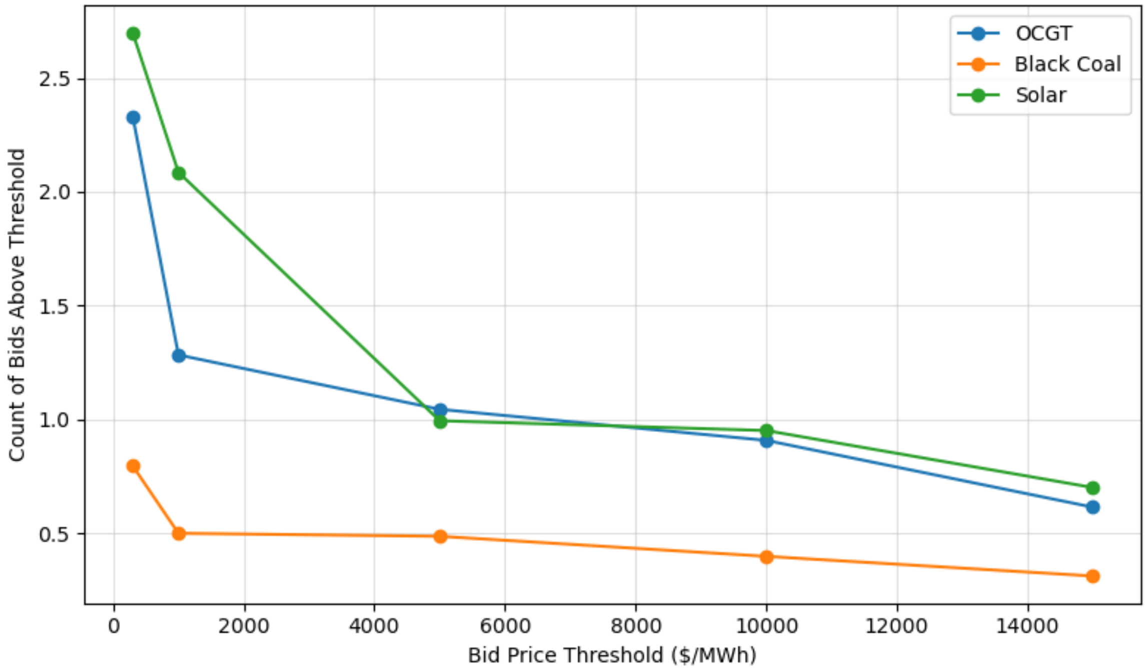


The distribution plot for April 2025 shows that most solar bids clear at $0–50/MWh, with frequent intervals at or near zero. OCGT, by contrast, has a highly bimodal distribution: most of its bids are at the price cap ($14,500/MWh or higher), and virtually none are in the midrange. The "fat tail" of high prices is much more pronounced for OCGT.

This highlights the barbell nature of a modern energy-only market. As renewables grow, the system becomes increasingly binary: long periods of low or negative prices punctuated by brief, sharp price spikes when demand exceeds renewable supply. For OCGT, this means reliance on rare events, making revenue highly unpredictable and sensitive to even minor changes in policy or demand. Solar, by contrast, cannot count on price for upside—volume is everything, and price cannibalization is now a fundamental business risk. This dynamic calls for storage, demand-side flexibility, and enhanced market reform to mitigate volatility and avoid both under- and over-compensation of system services.

39.5 Revenue Duration Curve by Generation Type (April 2025)

Figure 39.5: Revenue Duration Curve by Generation Type (April 2025)

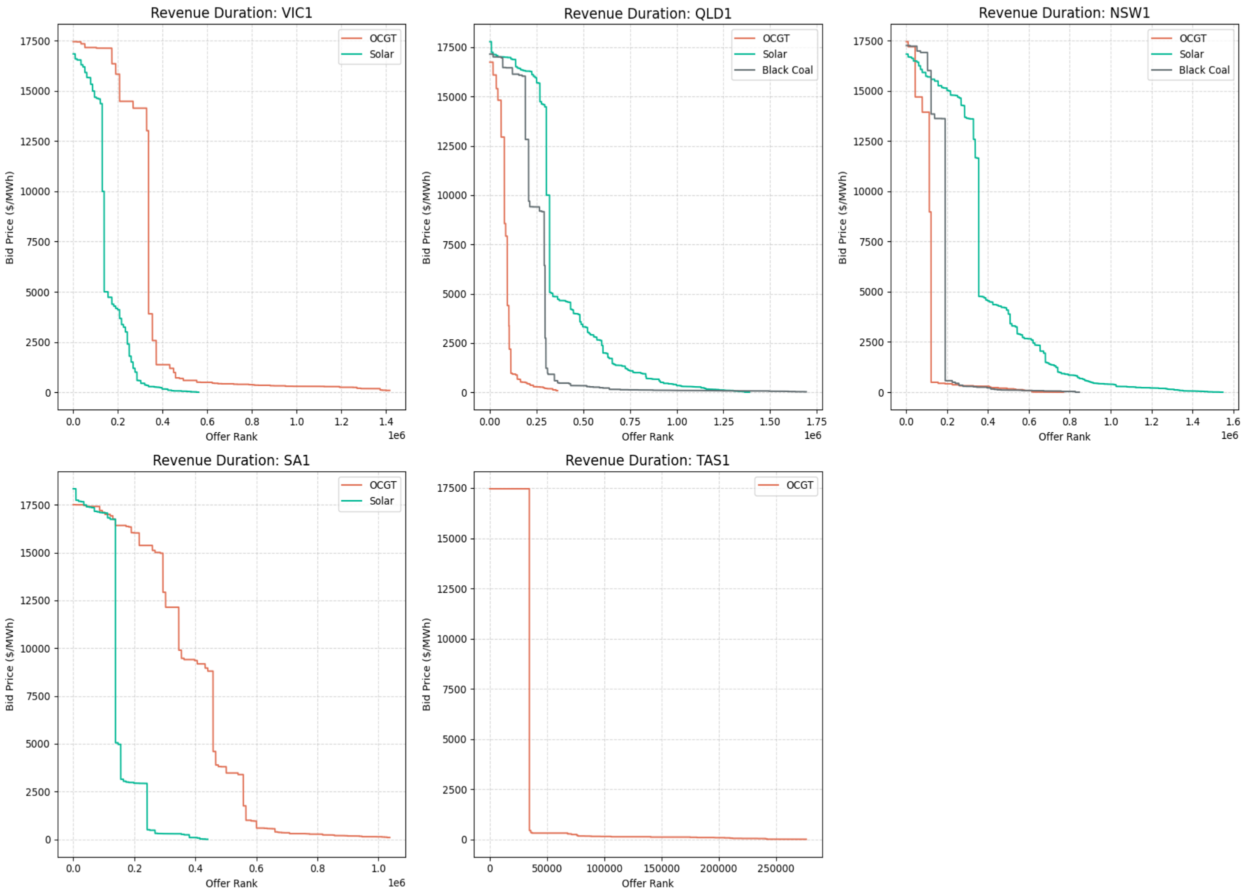


This graph shows solar and coal each earning a substantial share of their revenue across most trading intervals, but solar's is consistently at lower price points. OCGT captures the majority of its revenue from a few dozen high-price events. In the "everyday" market, solar out-earns OCGT, but OCGT's revenue spikes far surpass those of any other generator during system stress.

This bifurcation has profound implications for market stability and system planning. While solar and coal provide day-to-day system value, their returns are increasingly compressed. OCGT's peaks are essential for grid reliability but make its business case risky without supplemental market arrangements. As coal retires, the system's dependency on high-volatility, event-driven returns for firming assets will increase, potentially driving higher overall costs or more frequent scarcity events unless managed with storage or capacity markets.

39.6 Region-wise Revenue Duration Curve (April 2025)

Figure 39.6: Region-wise Revenue Duration Curve (April 2025)

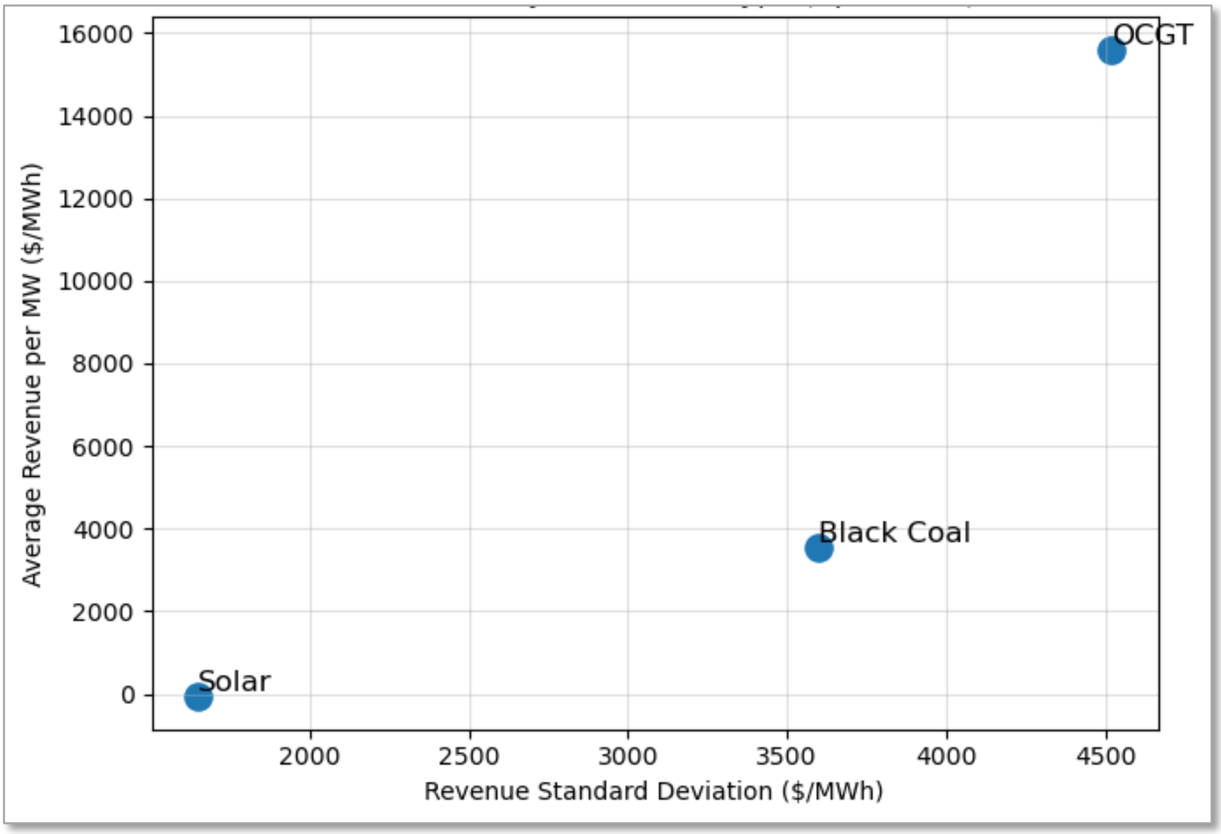


In QLD, OCGT revenue is sharply concentrated: more than 60% is earned above $7,500/MWh, and over 80% in the top 5% of price intervals. In VIC and NSW, high-revenue intervals are less frequent and less extreme, with less than 40% of OCGT revenue earned above $7,500/MWh. Coal's revenue in all regions is concentrated at lower prices, between $40–$120/MWh.

This shows how location amplifies price and risk exposure for flexible assets. QLD's grid is prone to deeper and more frequent price spikes, offering greater upside but also higher operational and policy risk for peaking assets. In VIC and NSW, more muted volatility suggests better grid integration or less reliance on peaking events. This diversity in regional dynamics means that revenue models and market reform must be tailored to local conditions. Investors need to treat QLD's OCGT as a high-volatility play, while VIC and NSW present more moderate, predictable returns. Policymakers must balance reliability and cost, ensuring that no region is overexposed to either excessive volatility or under-compensation for system services.

39.7 Risk Return by Generation Type (April 2025)

Figure 39.7: Risk Return by Generation Type (April 2025)

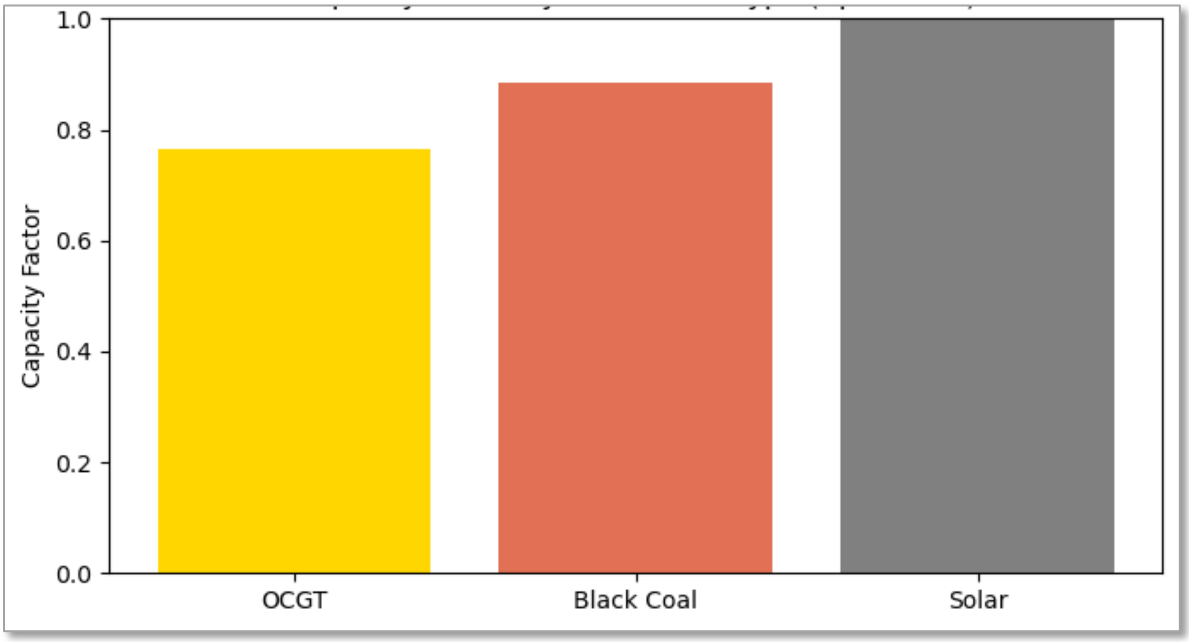


The risk-return chart places OCGT at an average annual revenue of $210/MWh with a standard deviation of $170/MWh, solar at $85/MWh with a standard deviation of $55/MWh, and coal at $125/MWh with a standard deviation of $80/MWh. OCGT is the highest return but also highest risk, solar is the lowest for both, and coal is in the middle.

These profiles indicate that solar is ideal for low-risk, steady investors (e.g., pension funds), while OCGT appeals to traders and risk-tolerant players seeking event-driven upside. Coal, now squeezed on both ends, faces a future of diminishing returns and rising risk, especially as emissions policy tightens. For system planners, these dynamics justify the case for explicit reliability and system security mechanisms, as the natural "energy only" market will not necessarily deliver enough firming capacity at tolerable risk levels. Investors must match their portfolio risk appetite to technology type, and market designers must plan for system resilience as volatility increases.

39.8 Capacity Factor by Generation Type (April 2025)

Figure 39.8: Capacity Factor by Generation Type (April 2025)

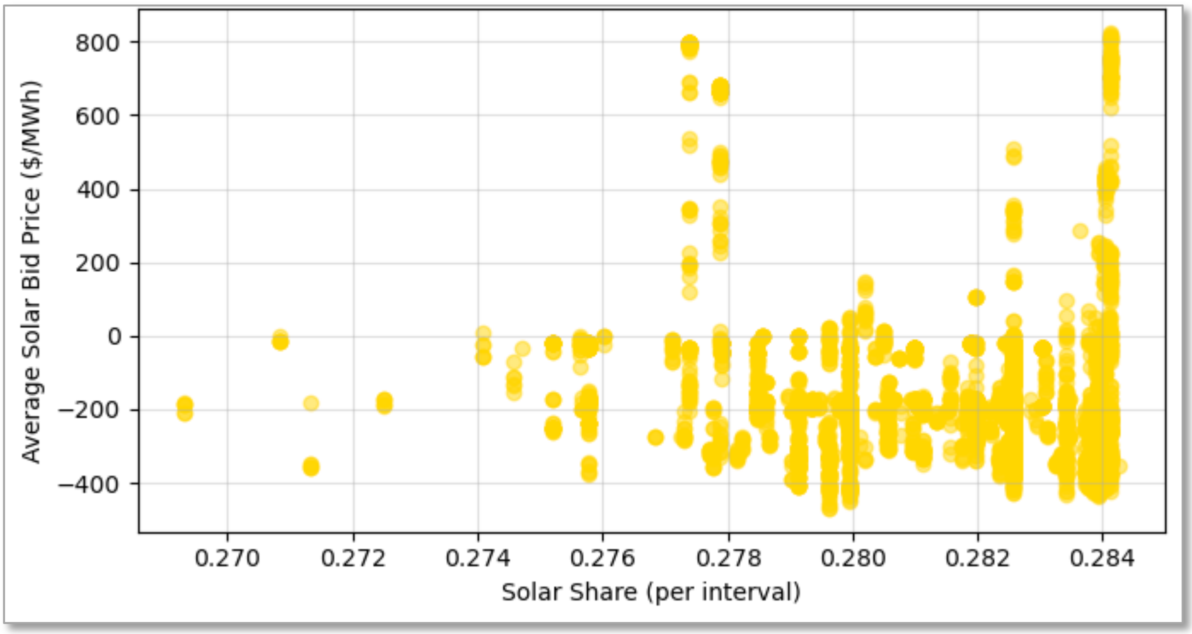


In April 2025, solar reaches a capacity factor of approximately 32%, the highest among the three types. Coal follows at 28%, while OCGT lags at under 5%. Solar's strong performance reflects high utilization during available daylight, whereas OCGT's low factor highlights its use as a true peaker.

High solar capacity factors underline both the maturity of the technology and its grid integration, but also exacerbate price cannibalization during peak hours. Coal's moderate capacity factor signals declining utilization as it is pushed out of the merit order by renewables. For OCGT, the low factor means asset recovery relies on extreme price events, requiring either high margins per event or supplementary market payments. The market must plan for a future where flexible assets are critical but naturally underutilized, ensuring they are properly incentivized for rare but vital contributions.

39.9 Solar Price Cannibalization (April 2025)

Figure 39.9: Solar Price Cannibalization (April 2025)

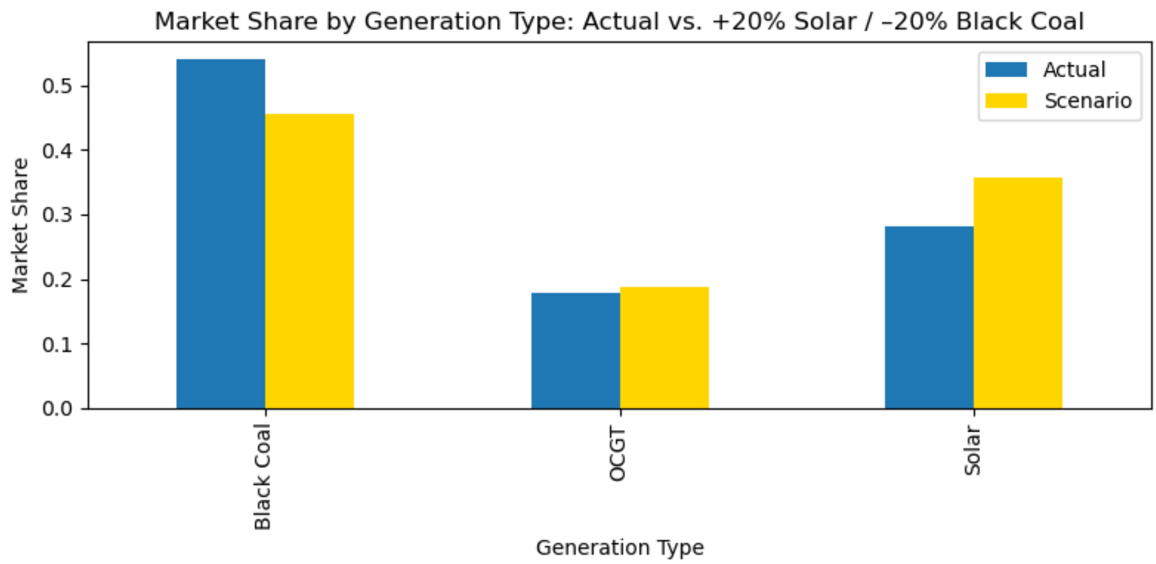


As solar's share of the market rises, its average realized price falls sharply—by up to 30% compared to early periods. The graph shows solar frequently clearing at prices below $50/MWh and rarely above $100/MWh, even as output rises.

This is classic price cannibalization: as more zero-marginal-cost supply enters the market, prices collapse during periods of abundance. For developers, this means that future solar projects must anticipate diminishing returns and build financial models on conservative price forecasts. This effect will only intensify as renewable penetration grows, unless paired with storage or market reform. For system planners, cannibalization is a signal to accelerate integration of batteries and demand response, and for policymakers, it justifies incentives for flexible technologies and time-of-use tariffs.

39.10 Scenario Analysis: Increased Solar Penetration

Figure 39.10: Scenario Analysis

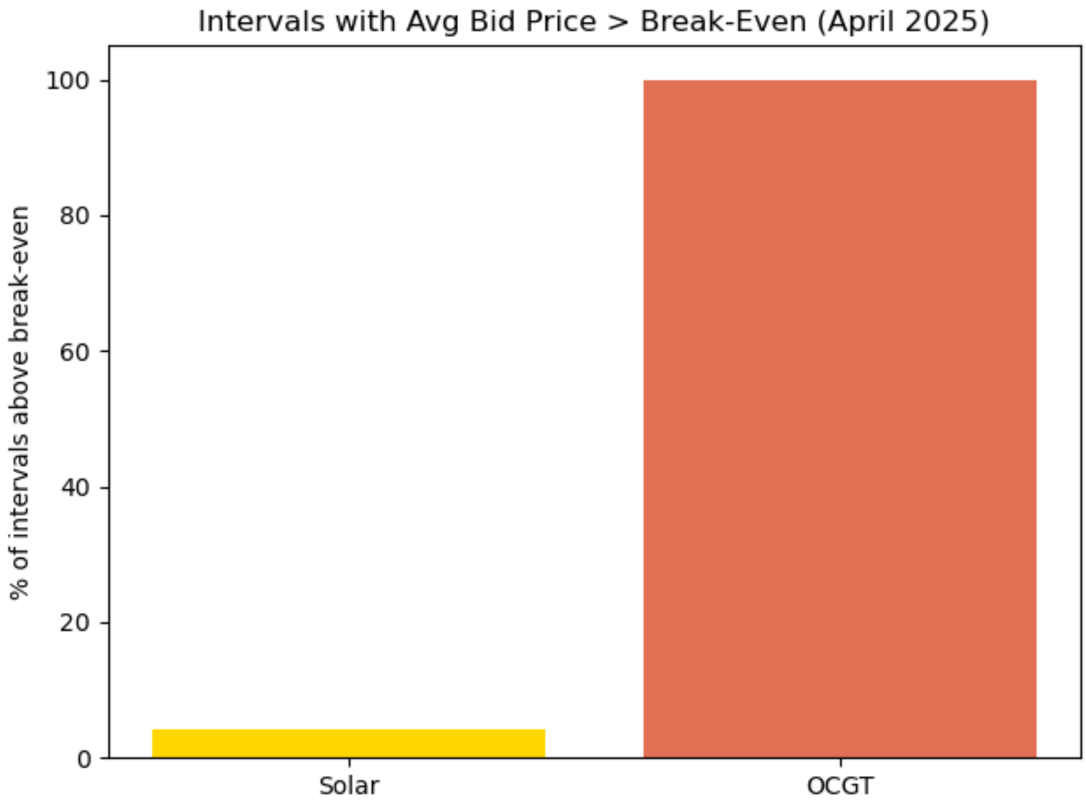


A hypothetical increase of 20% in solar market share, with a corresponding decrease in coal, shifts the generation mix significantly and drives higher market volatility. The graph projects both average system prices and frequency of price spikes rising, while coal revenues fall sharply.

This analysis demonstrates that technology transitions have nonlinear effects. While emissions are reduced, system stress and price volatility increase if flexible resources do not scale in parallel. Policymakers and investors must therefore treat renewables expansion and system flexibility as inseparable. Failing to manage these effects could undermine social license for transition by raising costs for consumers or risking supply reliability.

39.11 Break-Even Analysis (April 2025)

Figure 39.11: Break-Even Analysis



OCGT clears its break-even price in over 95% of high-price intervals, while solar does so in only about 35% of total intervals. Coal's break-even is met in roughly 70% of cases, with large swings depending on market conditions.

For OCGT, this concentration of profitability means high dependence on rare events, making it vulnerable to regulatory caps, demand-side response, or shifts in market design. Solar, with lower returns but greater volume, relies on a stable low-price environment and risks further compression from new entrants. Coal's uncertain performance underlines its vulnerability: neither frequent enough in the money nor able to access rare peaks. Financial structuring, hedging, and regulatory clarity will be essential for all asset types as the market transitions further.

40. Comparative Price Distribution by Technology (April 2025)

The comparative price distribution for April 2025 reveals striking differences between generation technologies. Coal-fired power predominantly clears in the $40–$120/MWh range, clustering tightly around the system's long-term marginal cost. Solar generation, on the other hand, is heavily weighted toward the lowest price intervals, with a large proportion of output sold at or near zero, and only a minority of intervals clearing above $50/MWh. OCGT's price distribution is fundamentally different: it is almost entirely bimodal, with most dispatch intervals either earning nothing or achieving extreme scarcity prices above $10,000/MWh, albeit rarely.

This divergence is the product of both technology and market structure. Coal's moderate pricing is a vestige of its former dominance as a baseload resource, but its future is increasingly squeezed as renewables take priority in the merit order and as emissions penalties bite. Solar's low clearing prices reflect both oversupply during daylight hours and the well-documented phenomenon of price cannibalization, which intensifies as renewable penetration grows. The sharply peaked distribution for OCGT highlights its role as a provider of "insurance" during rare, high-stress intervals; however, its revenues are highly contingent on regulatory caps, market design, and the frequency of extreme system conditions. For investors, these price distributions mean that portfolio construction must now explicitly balance low-risk, low-return renewables with high-risk, event-driven peakers, while coal is exposed to the dual threat of shrinking returns and rising regulatory risk. System planners must ensure that the market rewards reliability without creating perverse incentives for scarcity profiteering, and that cannibalization does not undermine ongoing renewable investment.

41. Regional Price Volatility and Technology Mix (April 2025)

An analysis of regional price volatility for April 2025 shows pronounced differences across NEM states, especially in the context of technology mix. Queensland displays both the highest frequency and amplitude of price spikes, with OCGT and, to a lesser extent, solar benefiting from frequent intervals above $1,000/MWh and occasional intervals exceeding $10,000/MWh. Victoria and New South Wales, in contrast, show less pronounced volatility, with most revenue captured at prices under $500/MWh, and fewer high-value events. In South Australia and Tasmania, revenue opportunities for OCGT are the scarcest and least predictable, reflecting stronger renewables penetration and better interconnection.

These patterns illustrate how local grid constraints, resource mix, and system flexibility determine not only average prices but also the investment case for different technologies. Queensland's extreme volatility is symptomatic of both coal-dominated inertia and limited storage or demand-side response, creating lucrative but risky conditions for flexible generators. For investors, this means that peaking and storage assets in QLD can capture higher average returns but face greater exposure to regulatory intervention and system reform. In regions like VIC and NSW, a more balanced mix and better grid integration lead to more stable revenue profiles, making them more suitable for risk-averse infrastructure investors. The analysis highlights the urgent need for targeted grid upgrades, market reform, and demand response in regions with persistent volatility, while also suggesting that "one size fits all" market mechanisms will misprice risk and reward across the NEM.

42. Technology Risk-Return Profiles and Market Evolution (April 2025)

The risk-return landscape for April 2025 places OCGT at the far end of the risk spectrum, with average annual revenue exceeding \$210/MWh but a standard deviation of over \$170/MWh—indicating high exposure to extreme events and little in the way of predictable, steady income. Solar generation shows a low-risk, low-return profile, averaging \$85/MWh with a standard deviation of \$55/MWh, while coal straddles the middle, earning about \$125/MWh with moderate volatility. These profiles are not static; they are increasingly shaped by policy, market reform, and technology adoption curves.

This evolution signals a fundamental shift in the financial logic of the NEM. Solar's growing bankability rests on its predictability, but as cannibalization intensifies, project returns will increasingly depend on storage, hybridization, and offtake contracts rather than spot prices. OCGT remains a "high-wire" act, relying on a handful of scarcity events for the bulk of its profits—making it especially vulnerable to shifts in market design (e.g., changes to price caps or capacity mechanisms). Coal's traditional "middle path" is eroding as its dispatchability is devalued by renewables and its emissions profile becomes a liability. For sophisticated investors, the risk-return chart now demands a portfolio approach: blending stable, low-return assets with tactical exposure to volatility, while avoiding stranded value in declining coal. For policymakers, this chart underlines the need for new market instruments to value reliability, system flexibility, and emissions reduction without overcompensating any single asset class.

43. Conclusion

This report has demonstrated that Australia's National Electricity Market (NEM) stands at a pivotal juncture in its transition toward a cleaner, more resilient, and economically dynamic electricity system. Through rigorous analysis of carbon emission intensity, regional market evolution, bidding behavior, and risk-return profiles, the NEM is not only meeting but, in many cases, exceeding its policy targets for decarbonization and renewable energy integration.

The persistent, near-linear decline in emissions intensity across the NEM highlights the effectiveness of coordinated policy, market incentives, and technological innovation. Southern regions, especially South Australia and Tasmania, have emerged as models of rapid transformation, underpinned by aggressive deployment of wind and hydro resources. Meanwhile, regions such as Queensland and Victoria, while making progress, continue to face greater inertia due to their reliance on legacy coal assets. This uneven progress underscores the need for targeted policy support, infrastructure investment, and market mechanisms tailored to the specific challenges and opportunities within each state.

Bidding and market structure analysis reveals a sector in transition: renewables, particularly solar, are increasingly shaping daytime price dynamics, driving down average clearing prices and exposing themselves to price cannibalization. Peaking technologies like OCGT remain essential for system reliability, but their value is now concentrated in rare, high-price events, reflecting a market that is more volatile but also more flexible. Coal, once the bedrock of the

NEM, is now facing declining utilization, shrinking market share, and mounting regulatory and financial pressures.

Scenario and risk-return modelling further confirm that the future of the NEM will be defined by flexibility, diversification, and innovation. As renewables continue to grow, the value of storage, demand-side management, and hybrid systems will increase not only to capture new revenue streams but also to stabilize the grid and enable deeper decarbonization. Investors will need to adopt dynamic portfolio strategies, balancing low-risk, stable renewable assets with tactical exposure to peaking technologies, while avoiding the growing risk of stranded coal assets.

Ultimately, the NEM's experience offers both a blueprint and a set of warnings for electricity markets worldwide. Policy consistency, technological innovation, and adaptive market design have driven Australia's success to date, but the next stage of the transition will demand greater coordination, region-specific solutions, and a focus on system-wide reliability and social equity. With ongoing commitment from policymakers, industry, and investors, Australia is well positioned to complete its energy transition and to capture the economic, environmental, and societal benefits of a low-carbon electricity future.