Key Drivers of Changes in 2024-25 CECVs

2024-25 CECV Update

Australian Energy Regulator | 18 Jun 2024

DISCLAIMER

This report was commissioned by the Australian Energy Regulator (AER) to provide an explanation of the factors that have driven the changes in the customer export curtailment values (CECVs) as compared to those in 2023-24.

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1. Background and objective of this summary note

As noted by the AER in the *Final CECV methodology*[1]:

> *Prior to 1 July each year we will consider whether input assumptions under the ISP's Step change scenario have materially changed to reflect new information or forecasts.*
>
> - If there are material changes, we will re-estimate CECVs using the new assumptions, update these values in the DNSP model and make subsequent changes to the number and nature of characteristic days in the DNSP model.
> - *If there are no material changes, we will only update CECV estimates to account for changes in inflation, to ensure that in economic terms, real values of CECV are maintained between CECV reviews. The annual adjustment mechanism is detailed in Appendix A. Instead of estimating new values for the 20th year of the analysis period, we will calculate new values based on the terminal value methodology discussed in section 4.2.1 (with the average of the final three years of values used as the new value for each half-hourly interval).*
>
> *New CECV estimates will be published by 1 July each year, as well as an updated list of data sources used for model inputs.*

This Note provides information on the key inputs to the calculation of the 2024-25 CECVs. As requested by the AER, this includes:

- Any inputs used this year that differ materially from those used in 2023-24.
- The degree to which those inputs (in aggregate) have resulted in changes to the CECVs themselves.
- The newly included avoided emissions profile due to additional CER export.

These changes are included in the CECV file and used to update the DNSP model, both of which are published separately by the AER.

[1] AER, *Final CECV methodology*, June 2022, p 10.

2. Overview of the CECV methodology

No changes have been made to the methodology used to calculate the CECVs for 2024-25 from that used in 2023-24. However, this year we have also estimated the avoided emissions profile for each region. This quarterly time of day (ToD) profile measures the reduction in system-wide emission at different points in time due to additional CER export (i.e., reduction in demand).

The main aspects of the CECV methodology are very briefly summarised below; full details can be found in the AER document entitled *Final CECV methodology* (June 2022).[2] We explain the methodology for calculating the avoided emissions profile in section 2.3 below.

2.1. Wholesale market modelling

Wholesale market modelling is the primary means by which the value that incremental DER export enabled by additional DER hosting capacity in the distribution network is quantified. This initial version of the methodology quantifies the impact of incremental DER export on:

- Wholesale market production cost (as opposed to price), accounting for aggregated headroom and footroom allowances for FCAS services, and
- Transmission and distribution losses.

The wholesale market modelling derives the half-hourly impact of additional DER export on each of the value streams noted above (or as expanded in the future) and combines them into a single CECV for each half-hour in each NEM region.

2.2. Value streams not estimated in the methodology

Potential value streams not included in the CECV methodology are:

- Other wholesale market value streams, such as
  - Possible changes to generation or transmission system investment costs, as this would require knowledge of the system-wide net effect of all alleviation projects
  - Changes in ESS provision where these might result in material differences to either the total amount of headroom and footroom allowances already included in the analysis or its allocation across the various FCAS services (i.e., 6 second, 60 second and 5 minutes)
- Network sector value streams, including avoided/deferred capex and avoided opex
- Potential competition benefits that additional export from DER systems could provide in the market
- The potential willingness of all customers to pay for the ability of the network to allow additional export from customer energy resources.[3]

2 This and other key documents related to the CECV methodology can be found at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/customer-export-curtailment-value-methodology/final-decision.

3 A full discussion of the value streams included in the CECV methodology can be found in AER, *DER integration expenditure guidance note*, June 2022, pp 220-26.

2.3. Avoided emissions profile

This is a new output to be made available with the CECVs. The amount of emissions reduction expected from investment that expands hosting capacity is an important consideration given Australia's carbon emissions reduction targets and because of the incorporation of an environmental objective in the NEO and the quantification of the value of carbon reduction that has been undertaken by the Commonwealth Department of Climate Change, the Environment, Energy and Water (DCCEEW).

To estimate the emissions impact due to CER export at different times, we established an hourly schedule of emissions reduction. This is mathematically different to calculating the half-hourly CECV itself. The CECV measures the marginal change in wholesale electricity (dispatch) cost due to an additional MW of CER export, which is routinely produced by the market model as the dual (or shadow price) of meeting the regional supply-demand constraint in each half-hour. However, to work out the marginal change in system emissions, one needs to explicitly perturb demand at different times (i.e., every hour).

In practice, doing so for every modelled half-hour over 20 years and 5 regions (which need to be simulated separately) would be a computationally burdensome exercise. A more streamlined approach was used which was to produce an average hourly[4] regional schedule for each quarter of each year over the modelling horizon. This involved the following steps:

- For each region, reduce the demand by a small amount (10 MW) for all (90) first half-hours (i.e., 90 occurrences of the midnight to 12:30AM interval) in Q1 of Year 1.
- Re-dispatch the model and calculate the emissions reduction NEM-wide for that quarter. Note that due to interconnectors and storage arbitrage, emissions reductions can sometimes come from other regions and at other times of the day.
- Divide the emissions reduction by the reduction in demand to approximate the marginal emissions reduction from an incremental DNSP export in this half-hour of this quarter for the said region.
- Move to the second half-hour and repeat.
- Repeat the above exercise for other quarters, other years, and other regions.
- The output of this exercise is an average hourly schedule of avoided emissions profile for each quarter in each financial year for each region. For the avoidance of doubt, this will result in there being 24 hourly emissions reduction values provided for each quarter in each year for each region. This average value is a proxy for the actual half-hourly values, the implications of which are discussed in section 5.

4 The average hourly profile by quarter was used to reduce computational constraint.

3. Changes to inputs and associated rationale

This section provides information on key changes to the inputs used to calculate the 2024-25 CECVs and the rationale for those changes.

3.1. ISP scenario used

The 2023-24 CECV inputs were based on AEMO's Draft 2023 IASR Orchestrated Step Change. The 2024-25 CECV inputs were based on AEMO's modelling data from the Draft 2024 ISP. This includes:

- CAPEX and Fuel cost inputs from the Final 2023 IASR Step Change Scenario.[5]
- Demand forecast from the Draft 2024 ISP Step Change scenario
- Coal retirement schedule and Transmission Optimal Development Path, except that to be consistent with the announcement made by the NSW government and Origin Energy on 23 May, the Eraring plant will now remain on-line until August 2027 rather than exiting service in 2025 as was assumed at the time the Draft 2024 ISP modelling was undertaken.

As with the previous CECV modelling rounds, the Step Change scenario is chosen, as it is generally considered the "central" scenario by the industry.

3.2. Changes in specific inputs

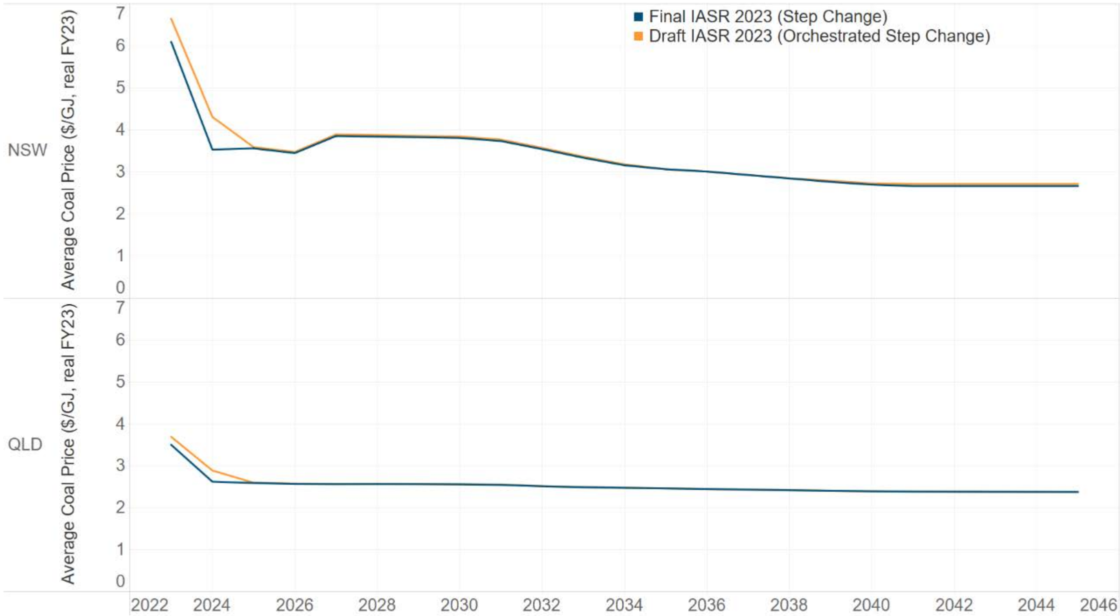
3.2.1. Fuel prices

The coal prices used in the 2024-25 CECV are similar to those used in the previous iteration. Coal prices are slightly lower than the previous inputs in the early years but converge to the same level after FY2025. The updated gas prices are lower in the current CECV modelling that those used for 2023-24.

Lower fuel prices lead to lower SRMC and will reduce the wholesale market benefit of additional CER export, leading to lower CECVs (holding everything else constant).

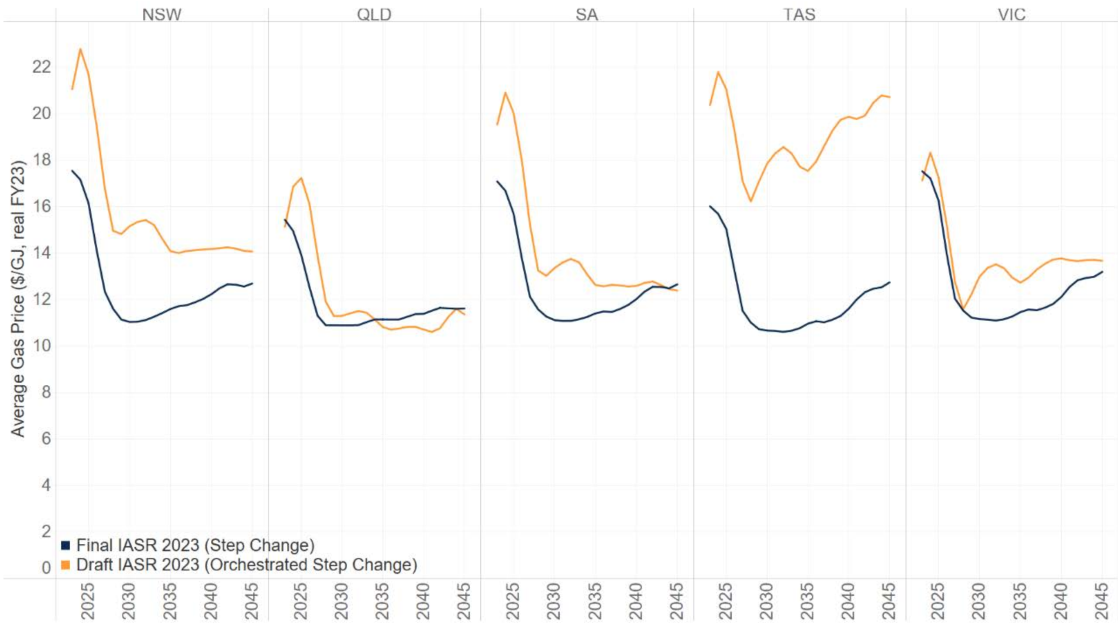
5 It is worth noting that the final 2023 IASR contains a single Step Change scenario,

Figure 1: Coal price forecasts comparison



Source: Endgame Economics analysis of AEMO's IASR

Figure 2: Gas price forecasts from the Draft 2023 IASR Orchestrated Step Change and Final 2023 IASR Step Change scenarios.

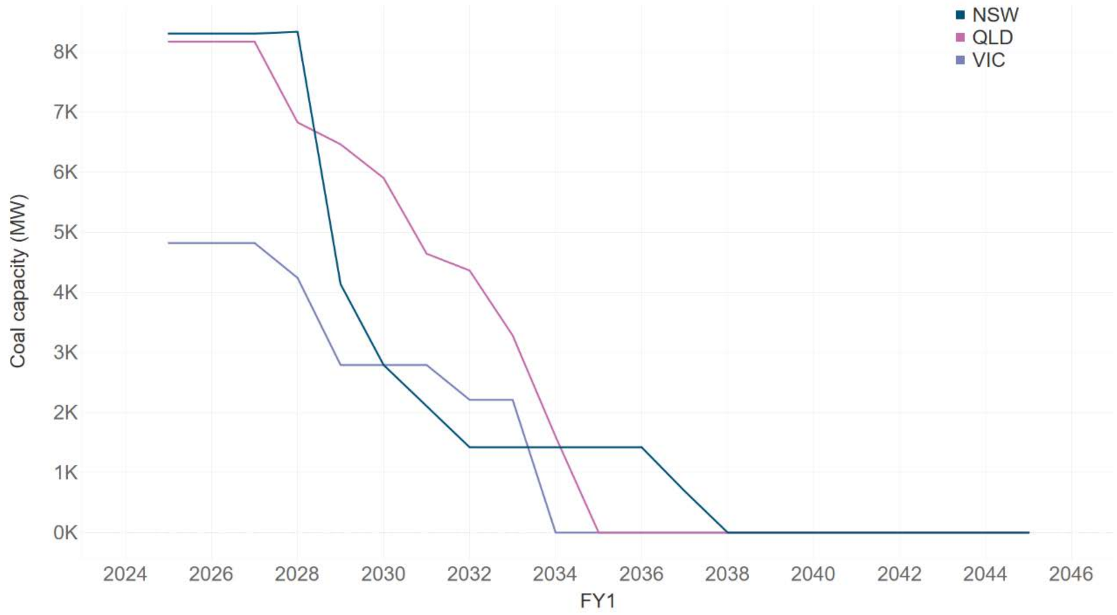


Source: Endgame Economics analysis of AEMO's IASR

3.2.2. Plant commitment and retirement schedules

The modelling undertaken for the 2024-25 CECVs incorporates updated information on the committed and anticipated plants based on AEMO's April 2024 Generation Information. Coal retirement dates are based on AEMO's draft 2024 ISP output. However, we have incorporated the announced two-year delay of Eraring's closure. As a result, all 4 units of Eraring are assumed to close on 17th Augst 2027 in our modelling.[6]

Figure 3: Coal capacity by region in the Draft ISP 2024 scenario.



Source: Endgame Economics analysis of AEMO's IASR

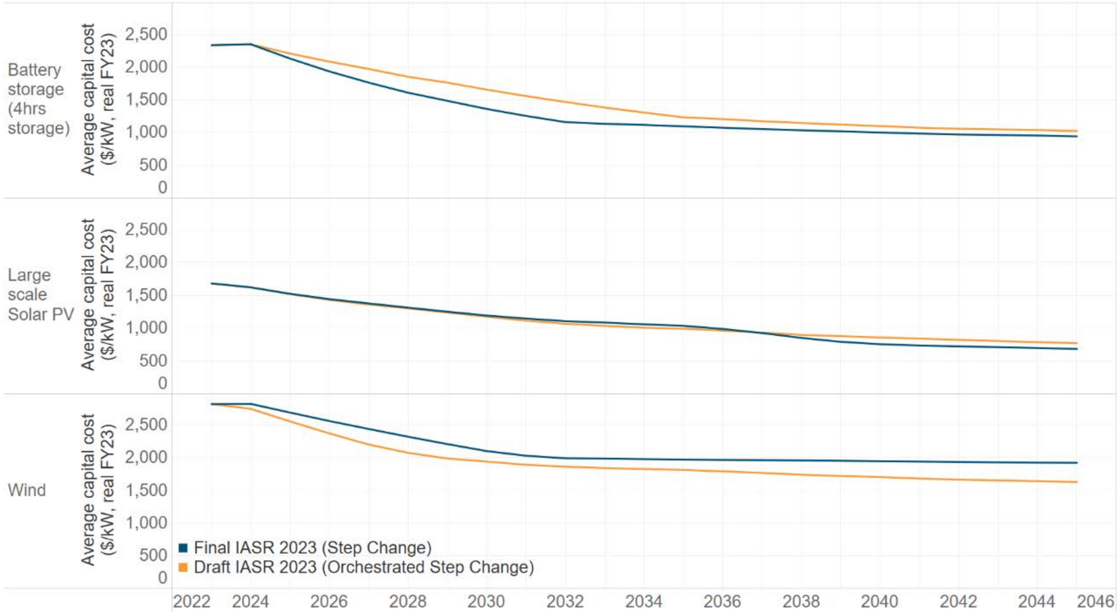
3.2.3. BESS and VRE capex

New Entrant CAPEX values are shown in the chart below. In summary:

- BESS CAPEX (using 4-hr as an example) in the current inputs experiences a faster cost reduction but converges to a similar level in the longer term as the inputs in 2023-24 modelling
- By contrast, wind CAPEX has increased in the current inputs throughout the modelling horizon compared to last year's modelling.
- CAPEX requirements for large-scale PV generation remain very similar to the values used in last year's modelling with costs in the final third of the modelling horizon being forecast to be a bit lower now than they were for last year's analysis.

6 https://www.environment.nsw.gov.au/news/nsw-government-secures-2-year-extension-to-eraring-power-station#:~:text=Origin%20has%20given%20notice%20it,must%20occur%20before%20April%202029.

Figure 4: BESS, large-scale PV and wind capex requirements from the Draft and Final 2023 IASR Step Change scenarios,



Source: Endgame-Economics

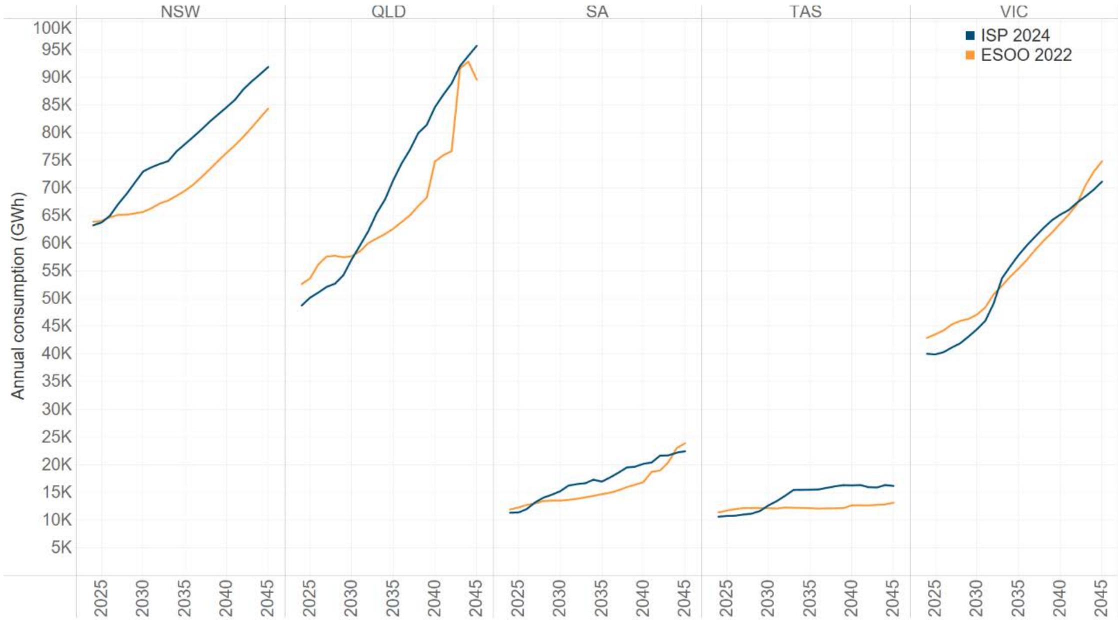
3.2.4. Energy consumption and maximum demand forecast

The modelling undertaken for the 2024-25 CECVs is based on the Draft ISP 2024 Step Change scenario demand forecast.

As shown in Figure 5 below, relatively high growth in consumption is expected in the Draft 2024 ISP in the early years in NSW, Queensland and SA (though from a lower base in the case of QLD). Growth starts later in TAS and Victoria. In last year's modelling, the energy consumption forecast (from ESOO 2022) ramps up in later years, eventually converging to a similar level of Draft ISP 2024 for Queensland, SA and Victoria.

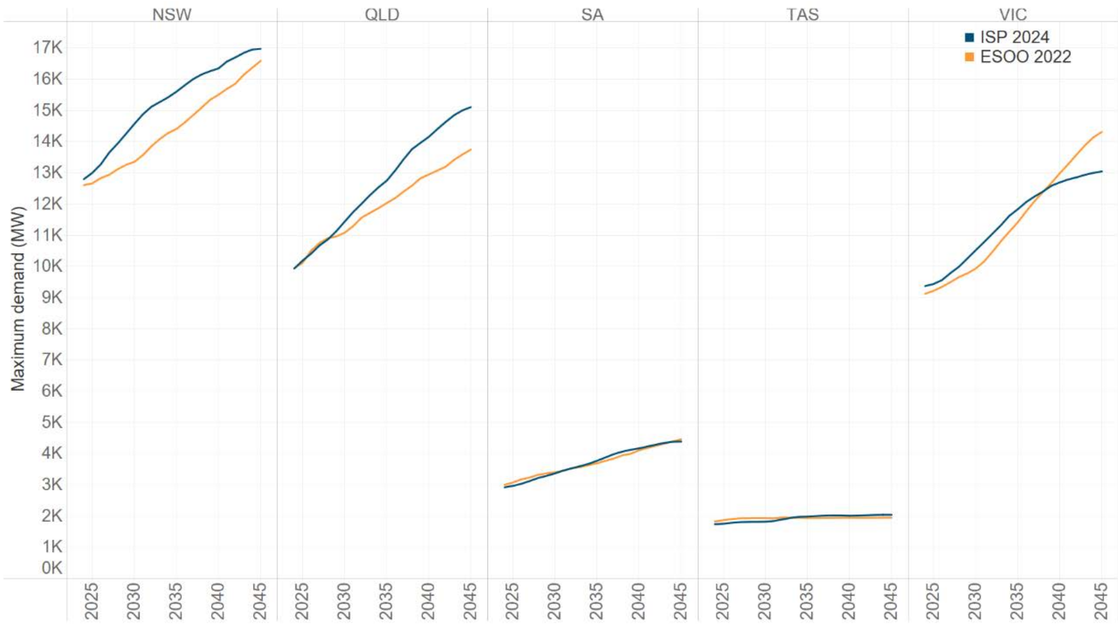
The maximum demand forecast is higher in the 2024-25 CECV modelling in NSW and Queensland. In Victoria, the maximum demand is slightly higher in earlier years but significantly lower in the later years, while maximum demand for SA and TAS remains very much the same in the 2024-25 forecast as was the case in 2023-24.

Figure 5: Annual consumption forecasts from the ESOO 2022 and the Draft ISP 2024



Source: Endgame-Economics analysis of AEMO data

Figure 6: Maximum demand forecasts (50POE) from the ESOO 2022 and the Draft ISP 2024



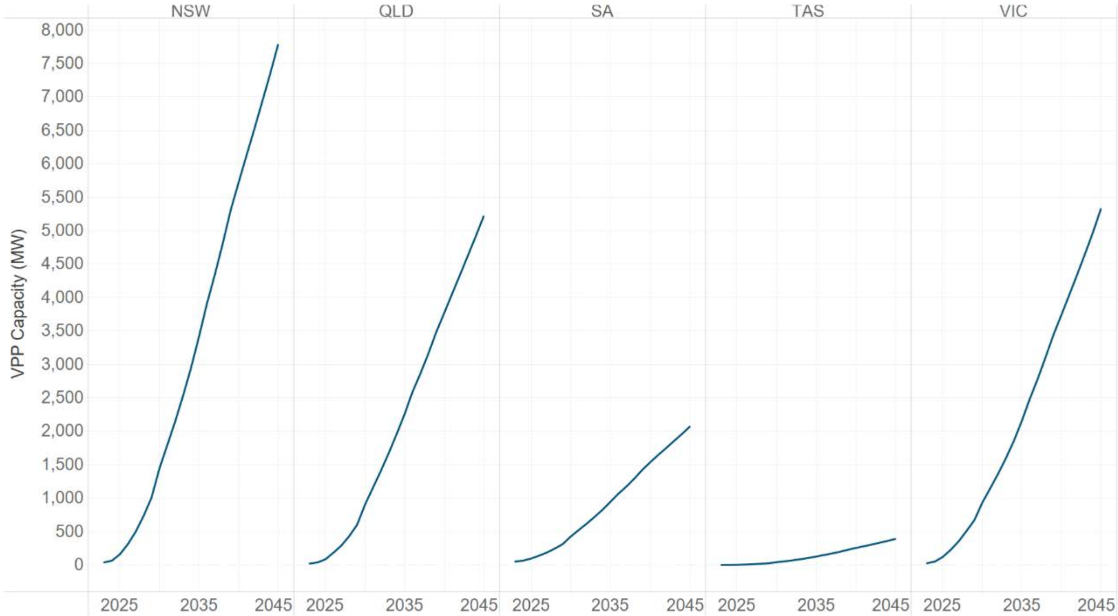
Source: Endgame-Economics analysis of AEMO data

3.3. VPP take-up

The level at which consumer energy resources participate in VPP arrangements is a key consideration for the CECV levels because a stronger uptake of VPP can be expected to lead to higher midday prices due to VPP operation, resulting in a material level of demand shifting. This occurs because the VPP coordinates behind-the-meter battery charging to occur during low-demand periods and discharging during higher-demand periods.

The figure below shows the forecast of VPP take-up that has been used. It is the same as that used in last year's modelling, as that forecast remained unchanged between the Draft IASR 2023 Orchestrated Step Change scenario and the Final IASR 2023 Step Change scenario.

Figure 7: Comparison of VPP take-up in the Draft and the final 2023 IASR



Source: Endgame-Economics analysis of AEMO data

3.4. State renewable energy policies

The final 2023 IASR includes meeting the Commonwealth Capacity Investment Scheme's NEM-wide target of 32 GW of renewable capacity investment by FY2030. This is a new target that has been incorporated in the current FY2024-25 CECV modelling. The other new addition is the Victorian Government's announced offshore wind target, which will deliver 2 GW, 4 GW and 9 GW offshore wind in Gippsland and Portland Coast in FY2032, FY2035 and FY2040.

The following renewable targets were already included in the 2023-24 CECV analysis and remain unchanged:[7]

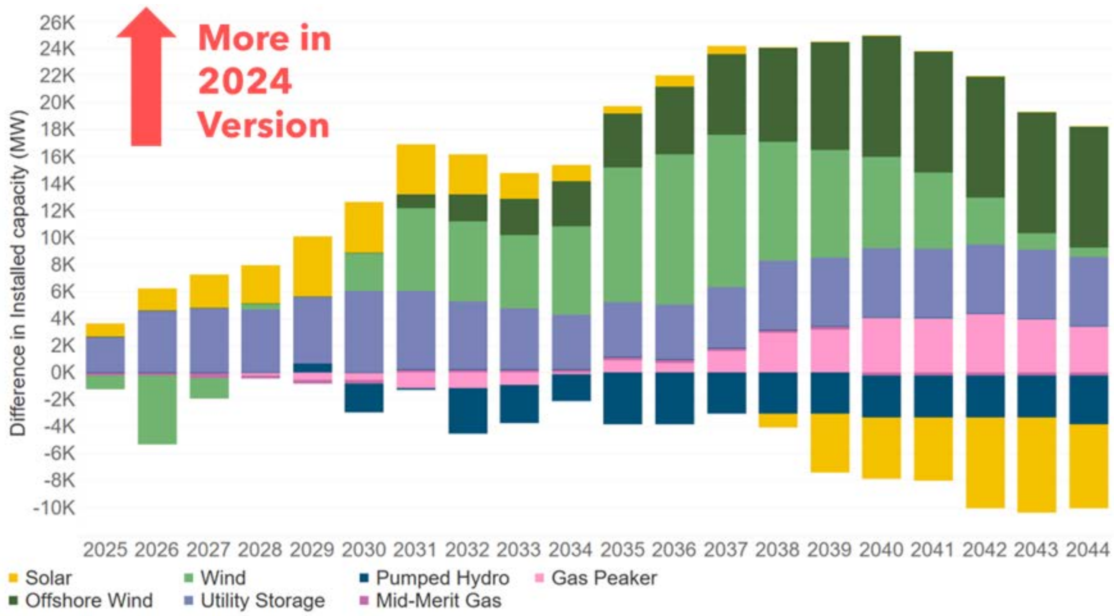
- NSW
  - NSW Electricity Roadmap Generation Target of 33.6 TWh of new VRE entrants (committed after November 2019) by FY2030.
  - NSW Electricity Roadmap Long-duration Storage Target of 2 GW 8-hour and above storage by FY2030.
- Victoria
  - Storage targets of 2.6 GW storage by FY2030 and 6.3 GW by FY2035.
  - VRET of 65% of the state's electricity generation by FY2030 and 95% by FY2035.

- Queensland Energy and Jobs Plan (QEJP)
  - QRET of 50%, 70% and 80% of the state's electricity demand by FY2030, FY2032 and FY2035.
  - Commissioning of the Borumba PHES (2GW/24hr) from FY2031.[8]
- South Australia
  - The 200 MWe hydrogen electrolyser load is included in the demand forecast. The 200 MW SA Hydrogen Turbine is included from FY2026.
- Tasmania
  - TRET of 15,750 GWh and 21,000 GWh of renewable generation by FY2035 and FY2040.

3.5. Differences in installed generation capacity between the years

Figure 8 below shows the differences in the installed capacity of different types of generation that result from the different inputs and assumptions in the IASR inputs used in modelling the 2023-24 CECVs and the IASR used in this year's modelling.

Figure 8: NEM-wide difference in installed capacity (MW) between 2024-25 and 2023-24 CECV modelling



Source: Endgame-Economics modelling output

The main drivers of these differences are:

- In the first few years, the difference is primarily due to the additional committed projects (mainly solar and BESS) in the Draft and Final 2023 IASRs.
- In the years leading up to FY2030, the 32 GW CIS target, which is incorporated in the Final 2023 IASR (but not the Draft), drives additional renewable capacity into the system.

8 The final 2023 IASR no longer treats Pioneer-Burdekin PHES as a committed entrant. The Model is still allowed to build generic new PHES entrants in Queensland.

- In the later years, higher demand growth in later years is generally offset by increased investment in wind and gas- or diesel-fired peaking plants, including the incorporation of the 9GW Victorian offshore wind target.

4. Summary of CECV outputs

This section summarises key factors that drive the CECVs, including forecast operational demand and the resulting generation profile, as well as several characteristics of the CECVs that result over the analysis period.

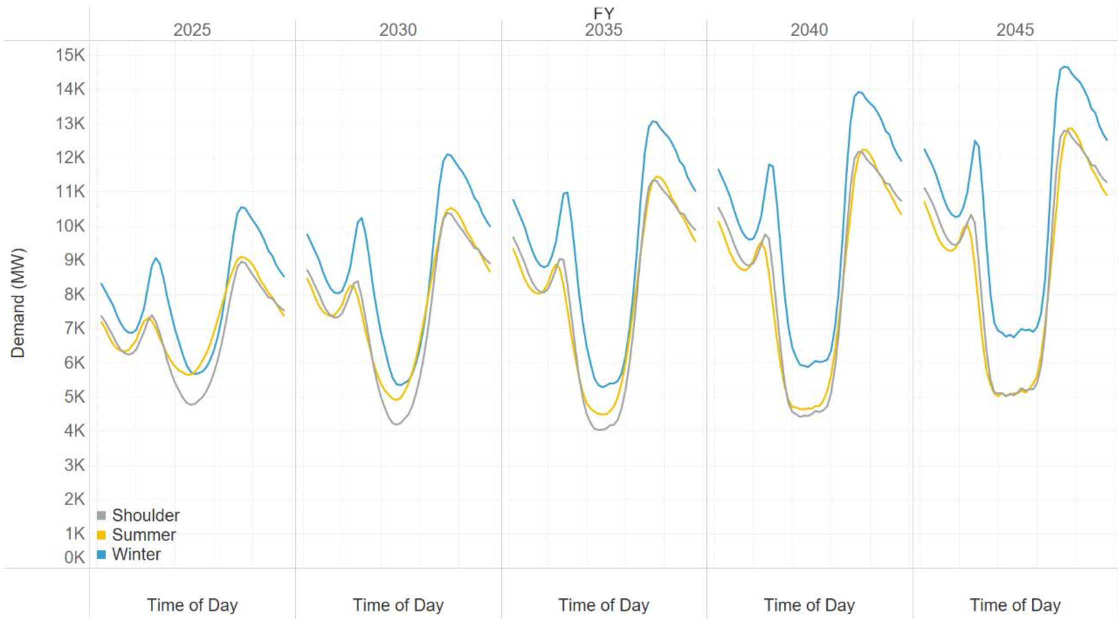
4.1. Operational demand

Figure 9 shows the seasonal operational demand in NSW in selected years to provide an example of the change in operational demand over the analysis period. The shape of operational demand is taken from AEMO's demand trace data from the Draft 2024 ISP Step Change scenario and reflects the impact of behind-the-meter rooftop PV generation, EV, and uncoordinated storage. The impact of coordinated BTM storage (i.e., VPP) is modelled endogenously and has not been incorporated into the chart.

As can be seen, the general shape of the operational demand within each season remains essentially the same over the years, but:

- The difference in the peak and trough of each season increases over time as more rooftop solar enters the system, and
- This difference between the shoulder and particularly the summer troughs and those in the winter increases markedly over the course of the analysis period.

Figure 9: NSW operational demand in selected years



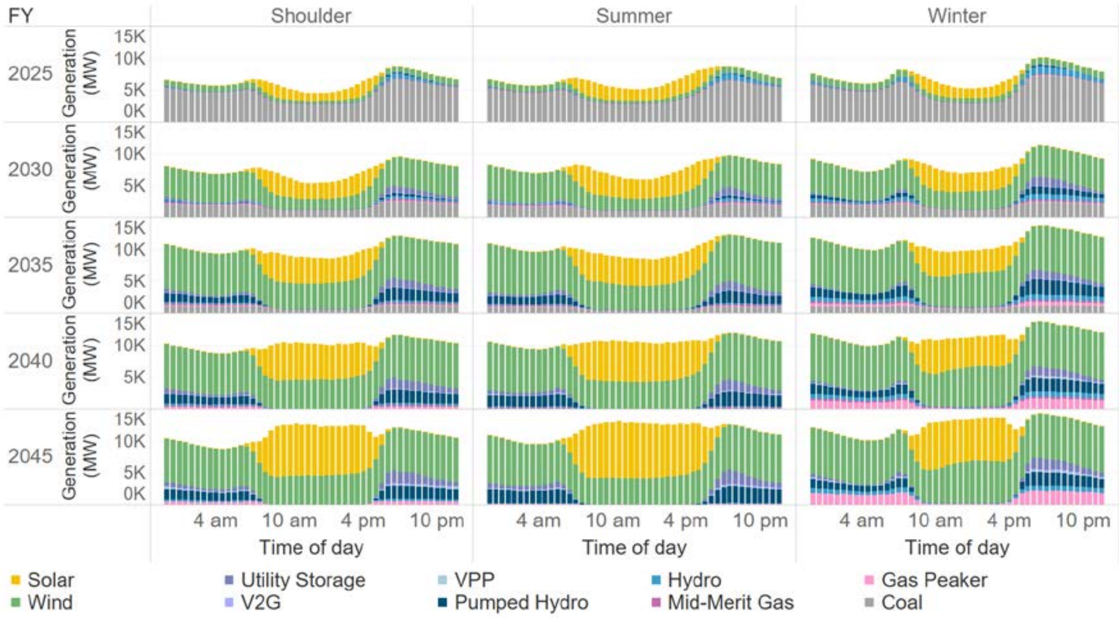
Source: Endgame-Economics analysis of AEMO data

4.2. Generation profile

Figure 10 shows the seasonal generation profile for NSW that results from the operational demand shown in Figure 9 above.

The changing capacity mix leads to significant changes in the generation profile, with later years showing greater production, particularly by wind and solar, and the retirement of base coal and gas. As coal retires from the system, demand growth and intermittent low availability of VRE resources, gas plays a larger (though still minor) role outside daylight periods in winter months in the later years.

Figure 10: Seasonal generation profile for NSW in selected years



Source: Endgame-Economics modelling output

The bulge in solar production in the middle of the day in the later years of the analysis period is not a product of native demand but rather the result of the deployment of large-scale BESS and pumped hydro, which charge in the middle of the day and then time-shift the solar production by discharging to meet demand in early to mid-evening hours.

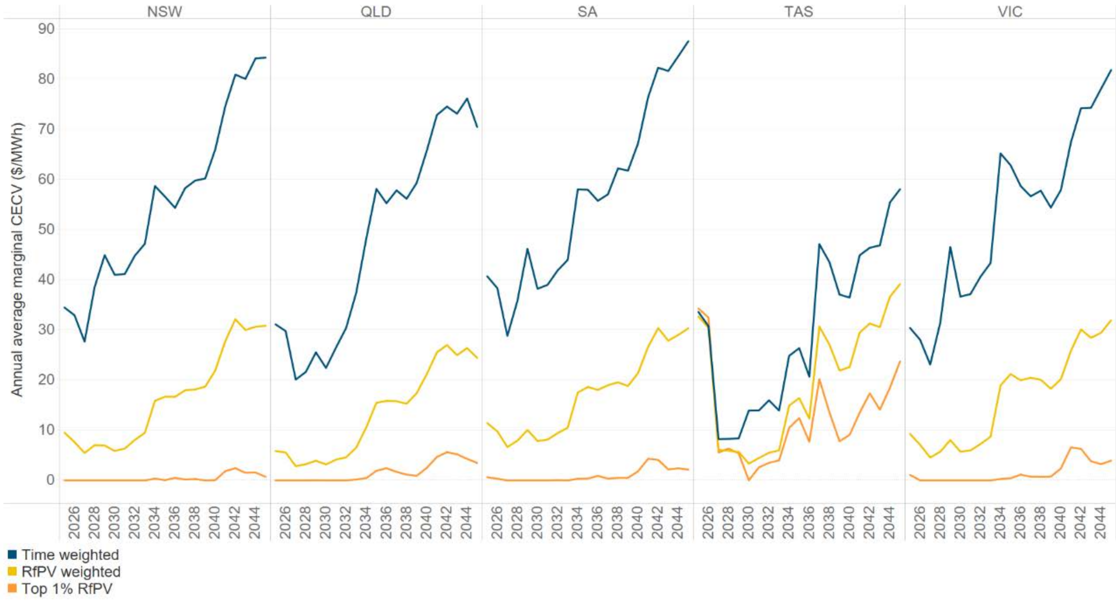
4.3. Annual CECVs

Figure 11 shows how three different measures of the average annual CECVs change over the analysis period for each of the NEM jurisdictions:

- The annual average time-weighted CECV
- A rooftop-PV output-weighted CECV (volume-weighted average of the CECV in all periods of rooftop PV electricity generation)
- The average CECV during periods of very high roof-top PV electricity generation (half-hour periods in which rooftop PV production is in the top 1%, which serves as a proxy for when curtailment is most likely to occur).[9]

9 Curtailment is actually most likely when rooftop PV production is high and underlying demand is low). Because these combinations cannot be readily simulated, the top 1% of PV production is used as a proxy.

Figure 11: Annual CECVs by jurisdiction over the analysis period



Source: Endgame-Economics modelling output

As can be seen, the annual average time-weighted CECV trends downwards in the initial years. This a product of there being more committed projects and additional renewable new entrants due to state and federal policies. Subsequently the CECV trends upwards in all regions, though with non-trivial dips and rebounds in some.

The upward trend is mostly due to increasing overnight prices as traditional baseload plants leave the system. The increase in the annual average CECVs reflects the underlying cost of supplying electricity in the future in a predominately renewable generation system. It should be noted that these are time-weighted, not dispatch-weighted costs, and do not represent an average of the time periods when most electricity is consumed. In addition they are costs, rather than prices, which can differ significantly.

These costs include the cost of building new renewable plants for bulk energy supply and building firming assets to ensure demand can be met when renewable availability is low. As the system could experience sustained periods of low wind and solar output, the firming requirements need to be met by assets with long storage duration. As gas build is limited by meeting the emissions constraint in the ISP, the system needs to build more storage assets to meet the firming requirements, leading to higher costs in the future.

At the other end of the spectrum, CECVs at times when rooftop PV output is at its highest (the Top 1% RfPV scenario) generally remain close to zero in all jurisdictions (except Tasmania due to increased rooftop and large-scale solar penetration exerting downward pressure on mid-day prices. They also slightly increase in later years as the need for BESS to charge at midday to provide generation at evening peak times increases.

The Rooftop PV-weighted CECVs generally sit between the two extremes but are essentially parallel in profile to the time-weighted annual average. Outside midday periods, pool prices generally increase over time due to continued bulk energy consumption growth and the withdrawal of coal plants.

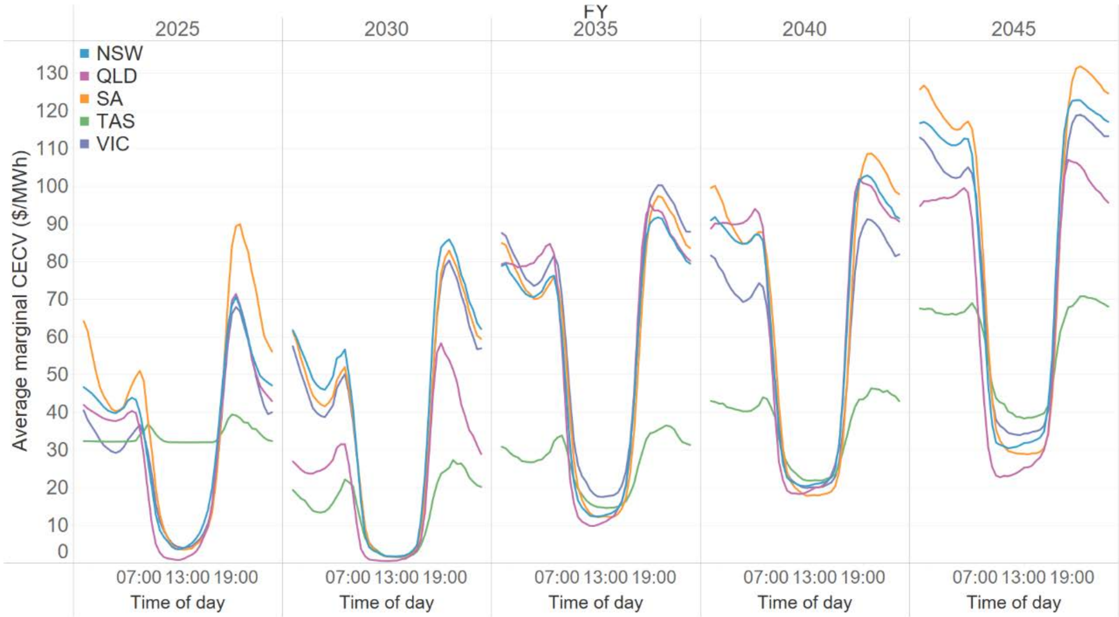
4.4. CECVs by time of day

Figure 12 shows how the CECV varies by time of day in each NEM region in selected years.

In the late 2020s and until the mid-2030s, increased solar penetration leads to suppressed prices during midday periods. However, evening and overnight prices remain high due to the need to run BESS and gas peakers to meet demand outside daylight periods.

From the mid-2030s onwards, the retirement of coal and continued energy consumption growth mean the system relies even more on gas and storage assets for firming. This drives evening and overnight prices even higher. After the mid-2030s, midday prices gradually trend upward as well. Demand growth and the withdrawal of midday min-gen production from coal plants mean that the instances of midday oversupply gradually decrease, particularly in winter, when solar output is less abundant.

Figure 12: Average annual time-of-day CECVs by NEM region for selected years



Source: Endgame-Economics modelling output

5. Avoided emission profile[10]

This section discusses the avoided emissions due to CER export at different times and the key drivers behind the marginal change in system emissions.

5.1. Avoided emissions by time of day

Figure 13 shows the annual average emissions reduction profile in selected years by perturbing demand in each region. This profile measures the average change in system-wide emissions due to a marginal demand reduction (or increase) in CER export in each hour in each region.

It is important to note that the average hourly value by quarter is a proxy for the actual change in emissions that would result from increased rooftop PV export on an hourly or half-hourly basis:

- The average approach overestimates the value of CER exports because, in reality, CER exports tend to be curtailed during periods when PV output (rooftop and utility) is abundant relative to demand.
- During these periods (i.e., high solar output vs demand), additional CER exports during midday will simply replace utility-scale solar generation and have zero emissions reduction value.
- Outside these periods (i.e., moderate solar output vs demand), additional CER exports during midday will tend to have greater emission reduction value:
  - In the early years, additional midday CER exports replace midday thermal generation directly.
  - In the later years, additional midday CER exports enable BESS to charge more during midday, which offsets evening peak thermal generation.
- The average approach gives equal weighting to both types of periods, but in reality, midday CER export curtailment generally happens when solar output is high relative to demand.

It is also important to note that a reduction in demand in a particular hour and region can result in an emissions reduction in other parts of the NEM and/or other hours of the day. The former is due to the fact that the NEM is an interconnected system. The latter is because storage can charge more in the hour with reduced demand. The stored energy can then be discharged at a different time, and this shift of energy from mid-day to evening peak results in additional displacement of thermal generation. This dynamic increases the emission reduction value at mid-day in later years when there is more storage in the system.

Generally, additional CER during the evening or morning peak times has a significantly higher emissions reduction impact because it is more likely to offset generation from marginal thermal units. Evening peak and overnight emission reduction values decrease in later years as coal retires from the system.

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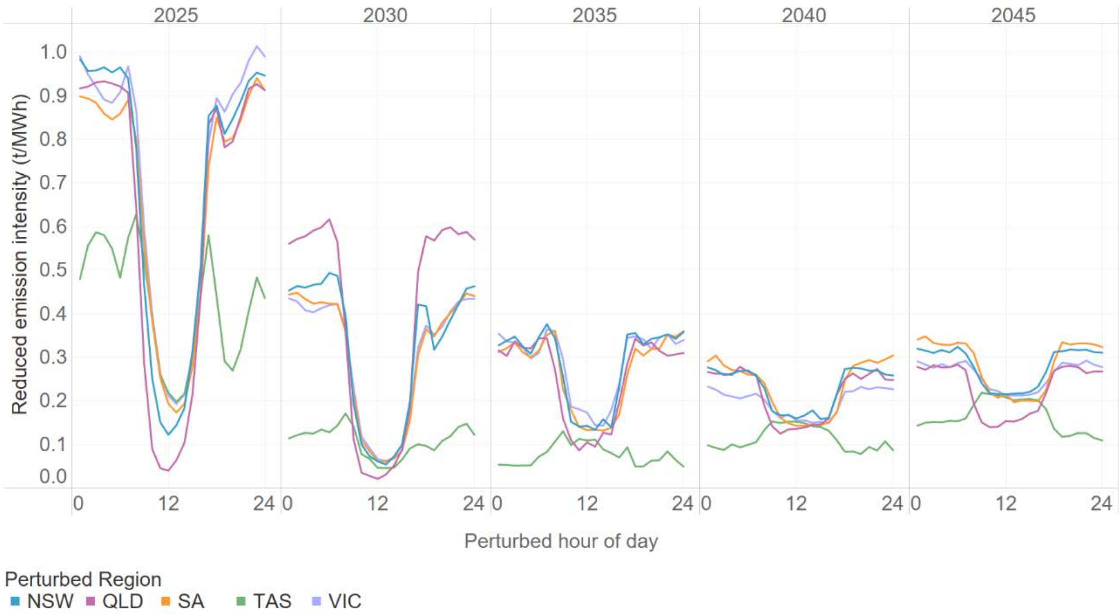
10 This section has not been updated with the effect of the extension of Eraring's operation. This will be updated in the final report.

Figure 13: NEM-wide reduced emission intensity profile (t/MWh) by perturbing different regions and time of day.



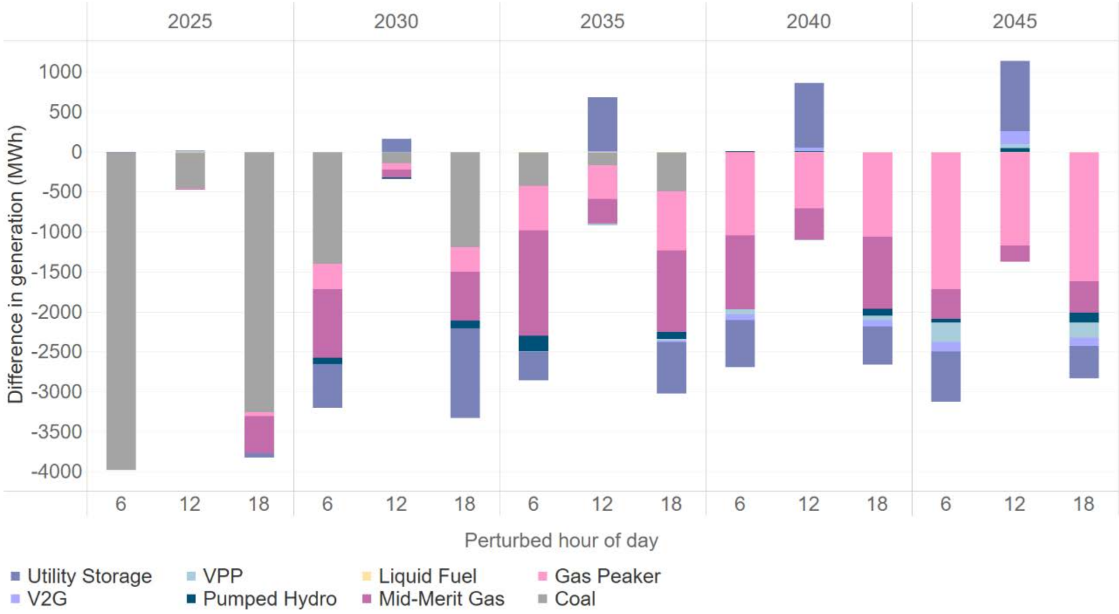
Source: Endgame-Economics modelling output

Figure 14, on the following page, shows the change in system-wide dispatchable generation due to a reduction in demand from selected examples of hours (6 am, midday and 6 pm) in NSW, noting that the change in production can come from other regions and other times of the day). We have not shown changes in wind and solar generation as they do not contribute to emissions.

In the early years, reducing morning and evening peak demand is likely to reduce the coal (and sometimes gas) dispatch at the same hour. Reducing demand during midday has a much smaller impact on dispatchable generation as it simply leads to further curtailment of large-scale solar generation.

In later years, as more BESS enters the system and coal exits, reducing morning and evening peak demand predominantly leads to lower gas output combined with some storage output reduction. Mid-day demand reduction promotes more charging from BESS. This leads to greater storage dispatch during peak time, which displaces thermal firming needs.

Figure 14: Annual difference in dispatchable generation by technology by perturbing NSW demand at 6am, 12pm and 6pm.



Source: Endgame-Economics modelling output

6. 2024-25 and 2023-24 CECVs compared

This section compares the difference between the 2024-25 CECV with the last year's results.

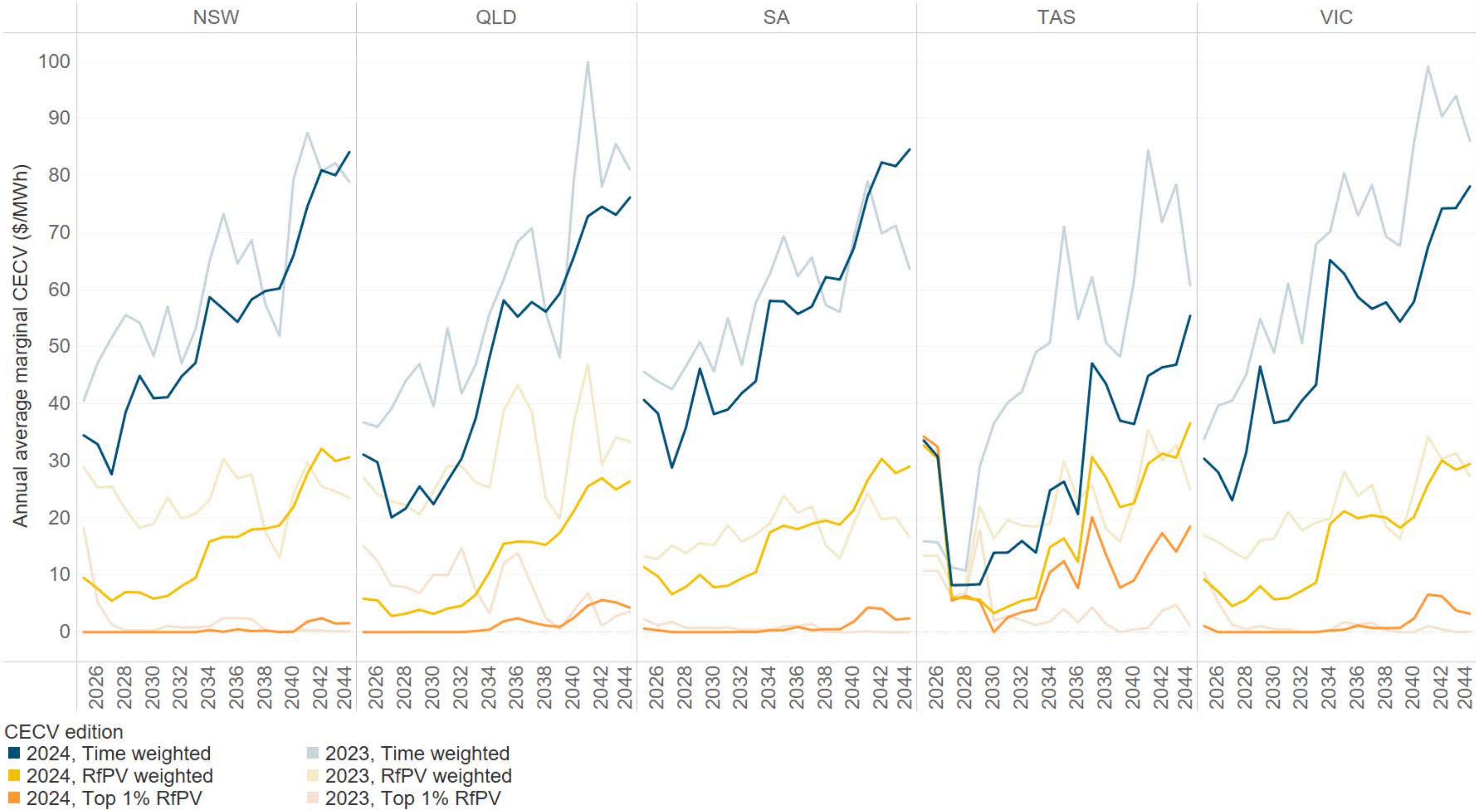
Compared to the 2023-24 results, the annual average 2024 CECV is generally lower across all regions. This is mainly driven by the additional renewable capacity in the system throughout the system over the modelling period, as shown in Figure 8 and discussed in section 3.5 above.

However, we note that the general trend in the CECVs between the current and last year's modelling is very similar. That is,

- The average level of CECV is low in the early years but grows in the long term due to coal exit and demand growth
- CECVs during the peak rooftop production period generally remain suppressed.

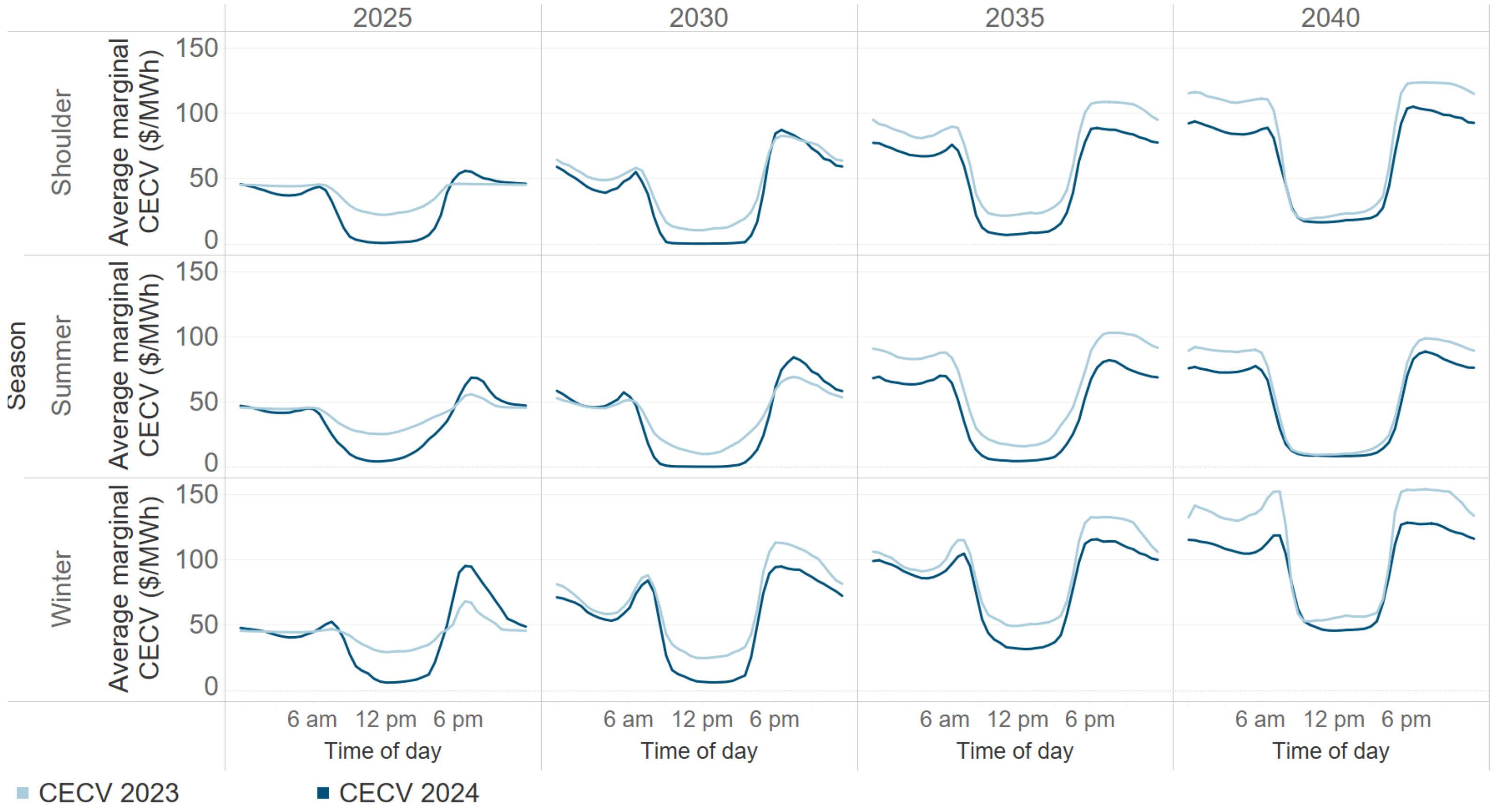
Figure 15 on the next page shows the average annual CECVs for each NEM region over the course of the analysis period. Figures 16 through 20, which follow, show the average seasonal daily CECVs for selected years in each state.

Figure 15: Average annual CECVs for each NEM region across the analysis period



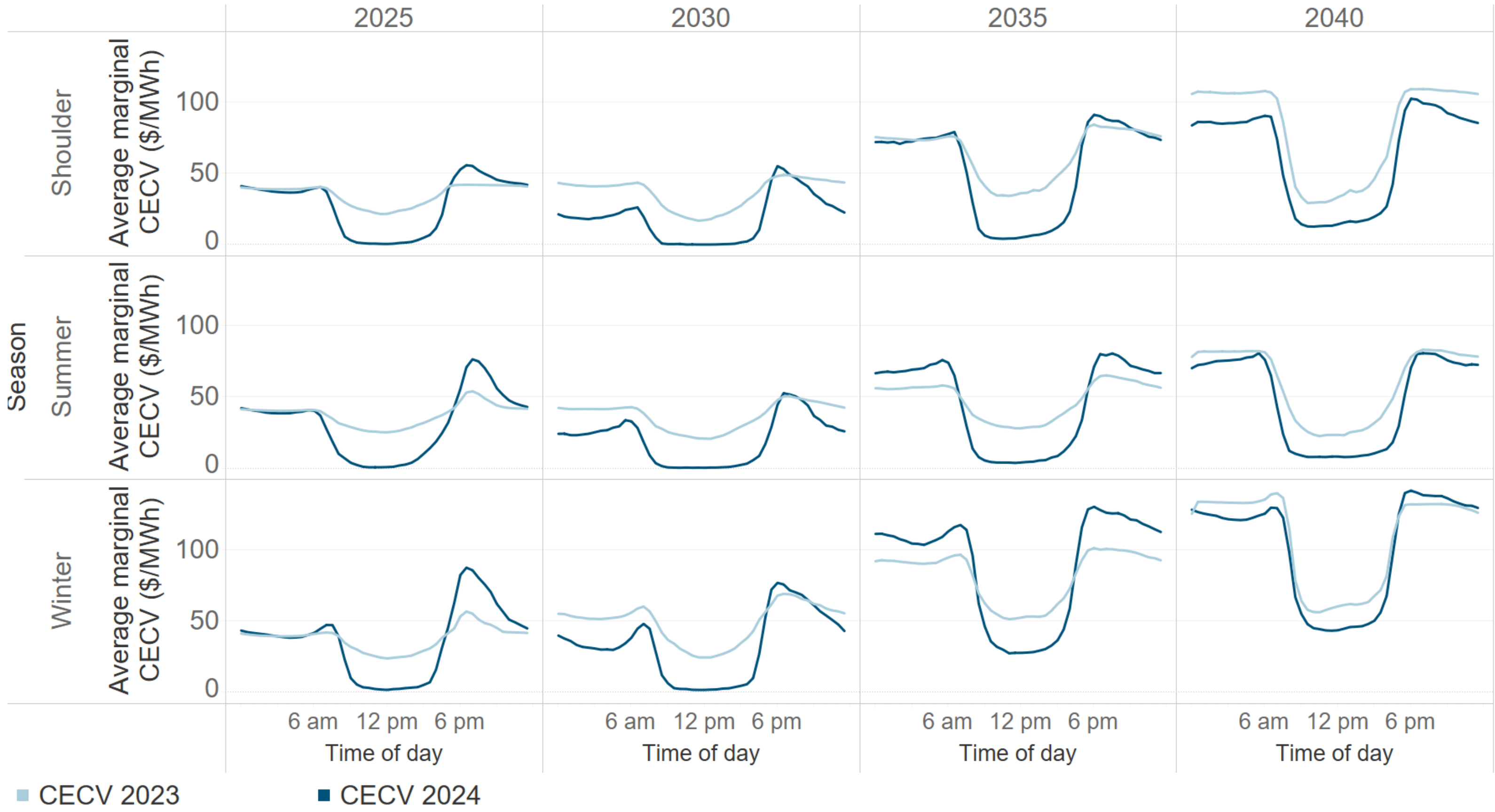
Source: Endgame-Economics modelling output

Figure 16: NSW average seasonal daily CECVs for selected years



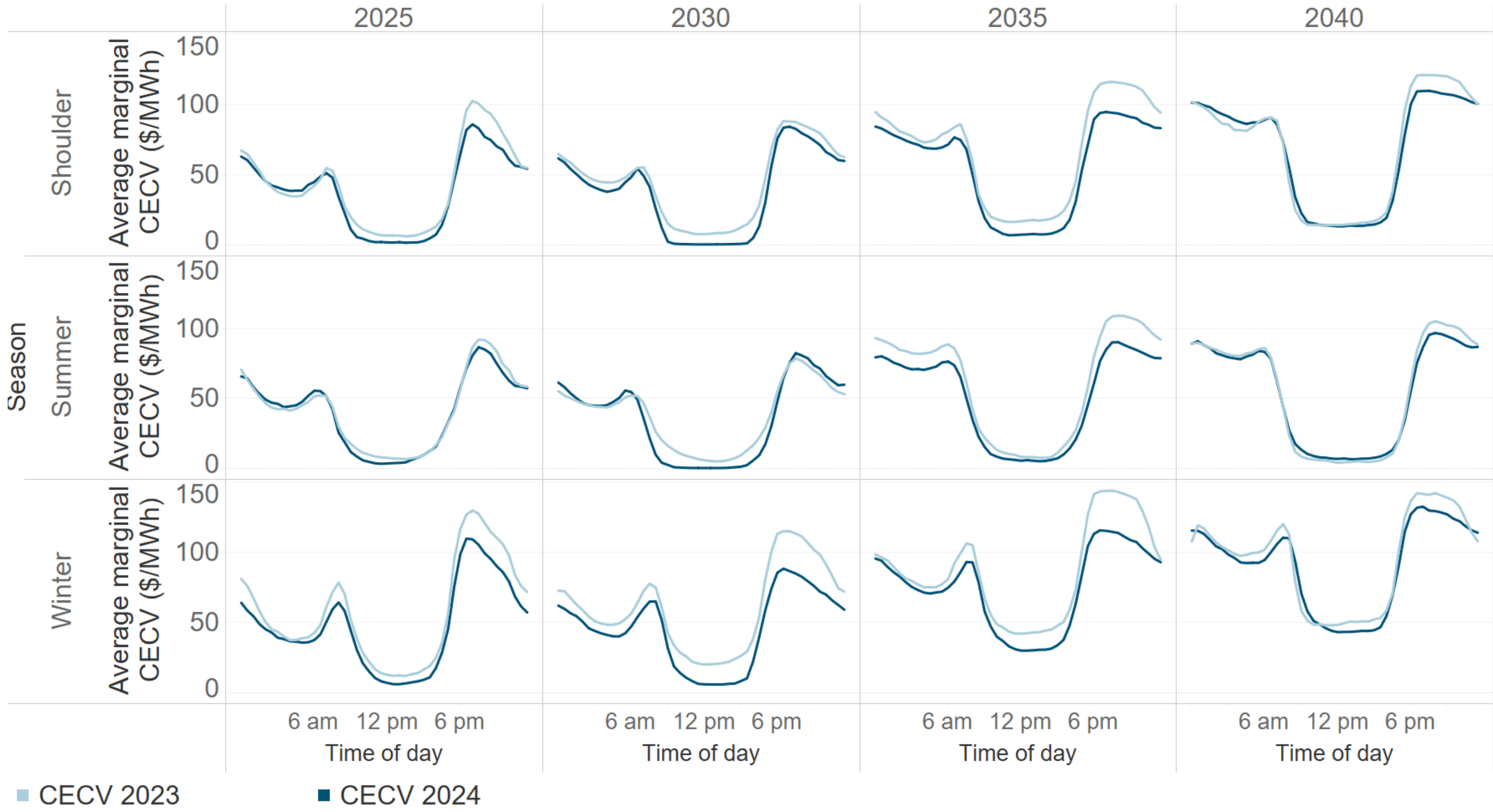
Source: Endgame-Economics modelling output

Figure 17: QLD average seasonal daily CECVs for selected years



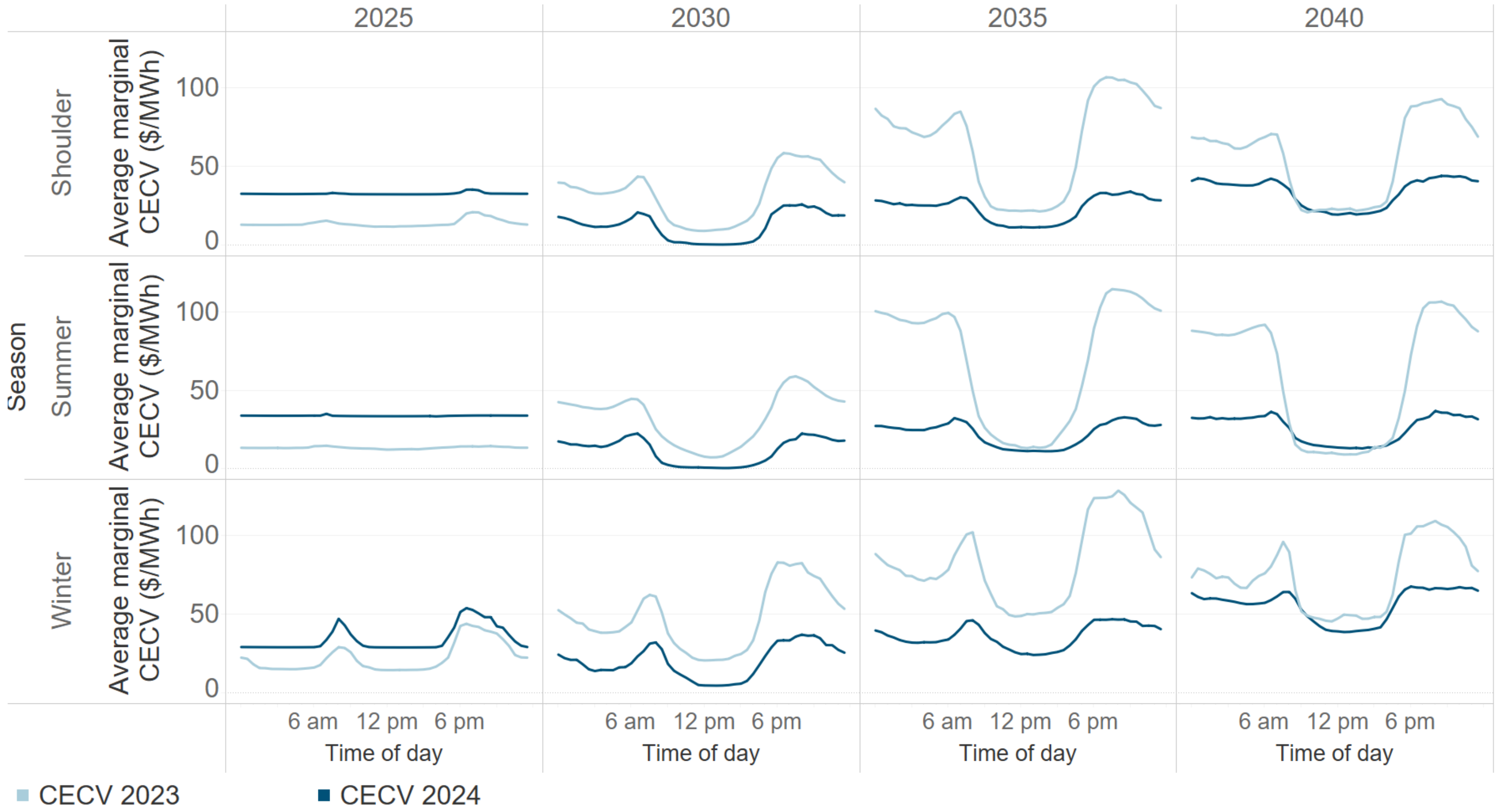
Source: Endgame-Economics modelling output

Figure 18: SA average seasonal daily CECVs for selected years



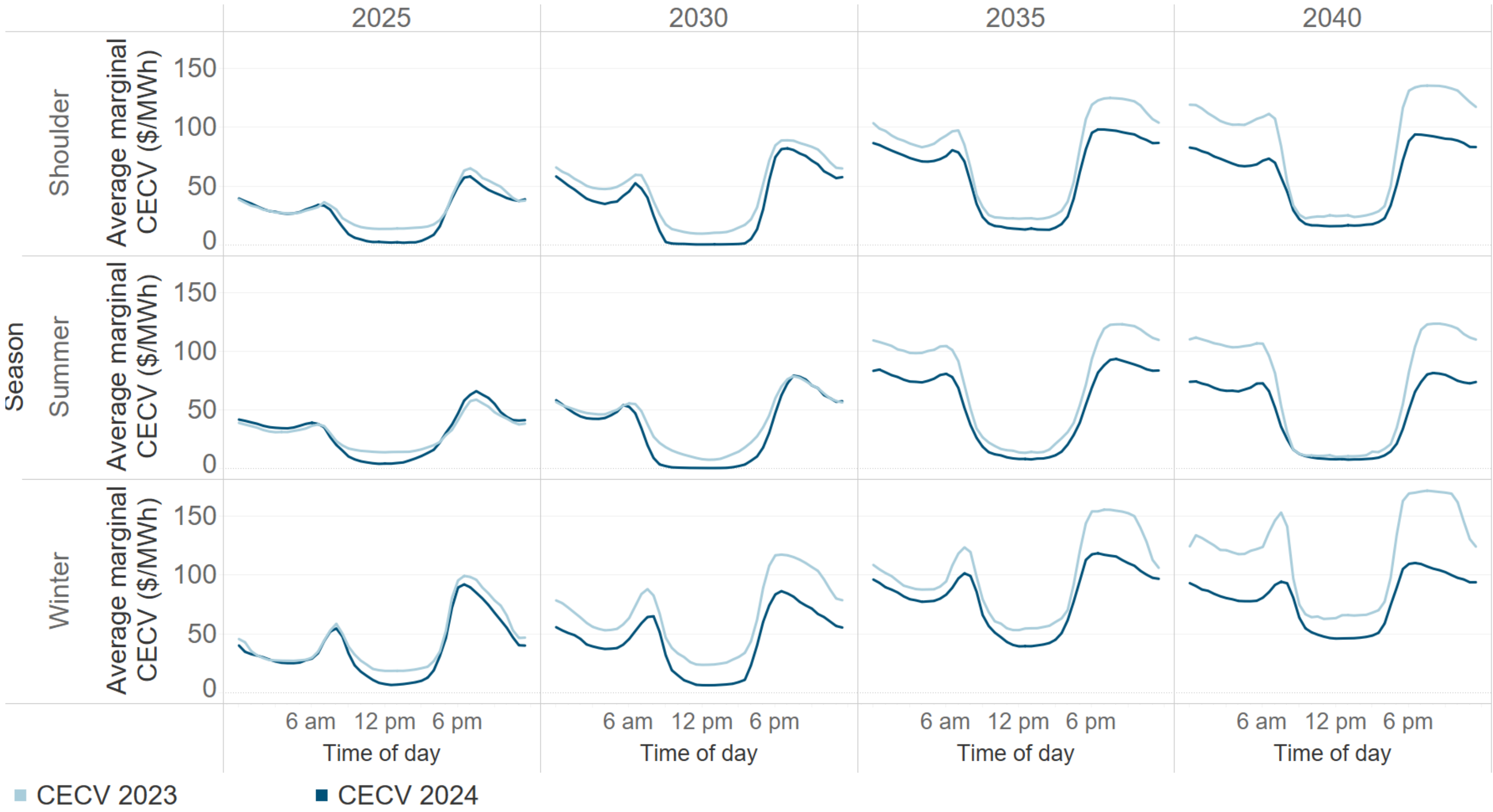
Source: Endgame-Economics modelling output

Figure 19: TAS average seasonal daily CECVs for selected years



Source: Endgame-Economics modelling output

Figure 20: VIC average seasonal daily CECVs for selected years



Source: Endgame-Economics modelling output

7. Impact of Eraring operation extension

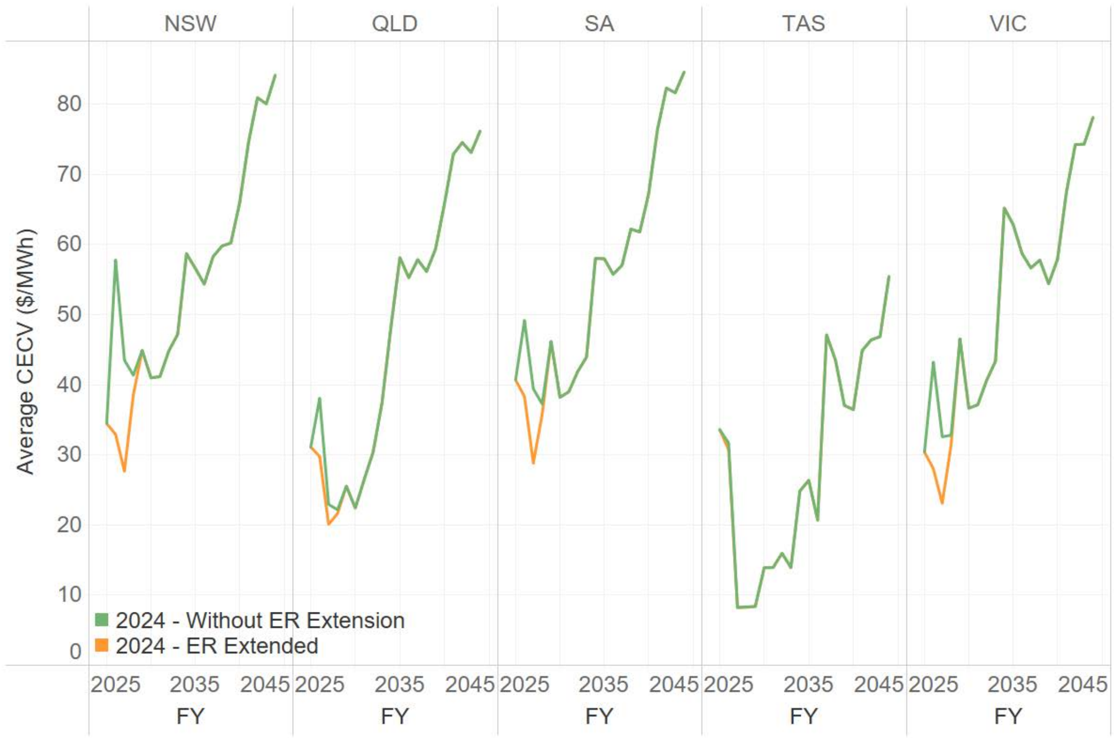
As noted earlier, the calculation of the 2024-25 CECVs (and emissions impact) includes the impact of the operational life of the Eraring plant being extended for approximately two years.

7.1. Impact on CECVs

Extending the 2800 MW Eraring plant to August 2027 will lead to lower wholesale electricity costs in the relevant financial years due to the increased supply from low-cost generation sources. The wholesale price reduction impact is approximately $25/MWh in FY2026 and $15/MWh in FY2027 in NSW. Other mainland NEM regions also see a reduction in wholesale prices, although to a smaller extent, due to the flow across interconnectors. The reduction in wholesale prices is the largest during evening peak and overnight periods when demand is highest and lowest during midday when there is generally an abundance of supply from rooftop and utility solar plants.

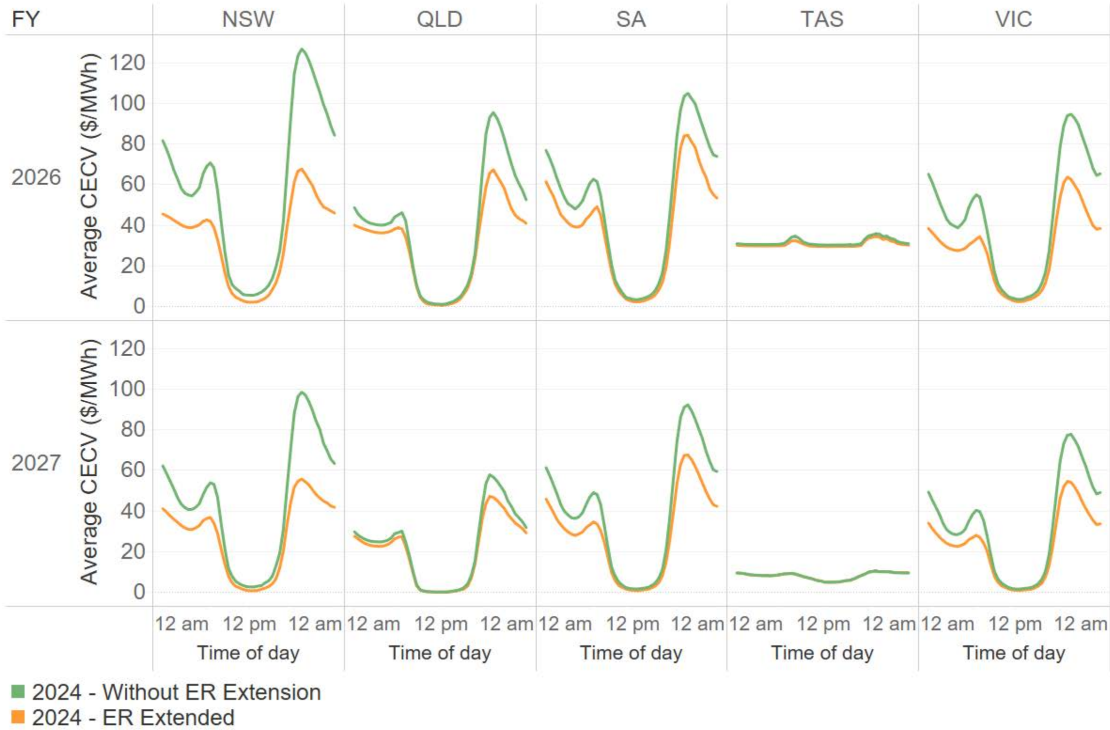
Figure 21 shows how the annual average CECV changes in the years affected by the extension of Eraring's operations in each of the NEM jurisdictions. Figure 22 on the following page shows its effect on the average daily profile of the CECVs in each of those years for each jurisdiction.

Figure 21: Impact of Eraring operation extension on annual average CECVs



Source: Endgame-Economics modelling output

Figure 22: Impact of Eraring operation extension on average CECV daily profiles



Source: Endgame-Economics modelling output

7.2. Impact on emissions profile

Extending Earing will lead to higher emissions reduction value due to additional CER export during evening peak and overnight periods. As coal is now more likely to be the marginal generation source during these periods, and their output level is above min-gen, an additional CER output will likely reduce more emissions. The emissions reduction impact of additional CER export during midday is lower. This is because there is generally an oversupply of energy through solar and inflexible min-gen output from coal plants in midday. Adding the inflexible min-gen output from Eraring during this time increases the likelihood that additional CER export simply replaces utility-scale solar without any emissions reduction benefit.

These impacts are shown in Figure 23 on the following page.

Figure 23: Impact of Eraring operation extension on emissions intensity