Modelling the Impact of Carbon Pricing on Australia's Electricity Markets

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Energy Market Modelling support for Carbon Pricing options
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Australia's Energy Transition: The Case for Carbon Pricing

Australia's energy transition is entering a pivotal phase. The policy landscape is at risk of fragmentation, with the Large-scale Renewable Energy Target (LRET) and the Capacity Investment Scheme (CIS) concluding in 2030, and post-2030 market settings still evolving. Meanwhile, the electricity sector must respond to rising demand from electrification, accelerating coal retirements, and the need to meet legislated climate targets: specifically, a 43% emissions reduction by 2030 and net zero by 2050.

In this context, carbon pricing offers a coherent, technology-neutral mechanism to guide investment, incentivise emissions reduction, and align market behaviour with national climate goals.

Purpose of This Report

This report was commissioned by the Grattan Institute to explore a carbon pricing approach that could reset Australia's energy policy trajectory: a sector-wide Emissions Intensity Scheme based on the Safeguard Mechanism. This is an approach that Australia has seen before.

We used energy market modelling to assess the feasibility and impact of this mechanism under carbon budgets consistent with achieving Australia's legislated emissions reduction targets in scenarios where the world acts to limit global warming to below 1.5°C and below 2°C, as defined by the Climate Change Authority. The goal was to provide evidence-based insights into how carbon pricing can support a more predictable, efficient, and credible transition for Australia's electricity markets.

Key Findings

- **Need for Stronger Emissions Abatement**
  Stronger emissions abatement than expected in the current reference case is needed to legislated targets. While renewables continue to grow, many emissions-intensive generators remain operational into the 2040s. Without coordinated policy reform, these legacy assets could delay the transition and jeopardise climate goals.

- **Faster coal retirement and higher Policy Costs for 1.5°C Scenario**
  Under the 1.5°C scenario, a tighter carbon budget accelerates the rollout of renewable energy, making coal generation economically unviable and hastening its retirement. However, this faster transition comes with higher costs compared to the 2°C scenario. This is largely due to the rapid infrastructure deployment required in the early 2030s. In contrast, the 2°C scenario allows for a more gradual shift, resulting in less pronounced cost increases.

- **Accelerated transition with the Extended Safeguard Mechanism**
  The extended Safeguard Mechanism enables an accelerated, phased transition under a technology-neutral policy, incorporating fuel switching and industrial decarbonisation. This policy option supports system stability through continued operation of centralised assets, especially gas-fired plants.

- **Urgent action required**
  By financial year 2027, only 376 MtCO_2-e remains in the 1.5°C budget and 574 MtCO_2-e in the 2°C budget for the power sector through to 2050. For context, electricity generation emitted 152 MtCO_2-e in calendar year 2024.

Policy Recommendations

Carbon policy reform, such as the approach proposed by the Grattan Institute, could offer a more coherent framework for emissions reduction.

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Acronyms and abbreviations

Acronym	Definition
ACCC	Australian Competition and Consumer Commission
ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
AGL	Australian Gaslight Company
APA	Australian Pipeline Association
ASX	Australian Stock Exchange
BESS	Battery Energy Storage System
CCA	Climate Change Authority
CCGT	Combined Cycle Gas Turbine
CIS	Capacity Investment Scheme
CISA	Capacity Investment Scheme Agreement
CPI	Consumer Price Index
DER	Distributed Energy Resources
DKIS	Darwin Katherin Interconnected System
EGP	Eastern Gas Pipeline
EIS	Emissions Intensity Scheme, a market-based scheme that sets a benchmark emissions intensity for a specific generator or portfolio of generators. Facilities that emit less than the benchmark can generate credits, and those that emit more must purchase credits to offset excess emissions. This approach now aligns with Australia's Safeguard Mechanism.
EITE	Emissions Intensive Trade Exposed
ESOO	Electronic Statement of Opportunities
EV	Electric Vehicle
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
GWh	Gigawatt hour
IASR	Input, Assumptions and Scenarios report as published by the Australian Energy Market Operator

Acronym	Definition
ISP	Integrated System Plan as published by the Australian Energy Market Operator
kWh	Kilowatt hour
LNG	Liquified natural gas
LRET	Large scale Renewable Energy Target
LRMC	Long run marginal cost
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NWIS	Northwest Interconnected System
NZE	Net Zero Emissions Scenario, which outlines a pathway for the global energy sector to reach net zero CO_2 emissions by 2050, in line with the Paris Agreement's 1.5°C climate goal.
PCA	Production Concession Agreement, a contractual agreement granting rights to explore and produce hydrocarbons.
PJ	Petajoule
PKET	Port Kembla Energy Terminal (LNG)
PoE	Probability of exceedance. This term usually refers to the probability that a demand forecast will be exceeded. A 50 PoE demand forecast is expected to be in the middle of future outcomes, being exceeded roughly half the time.
PV	Photo Voltaic
NSG	Non-scheduled generation, describing electricity generation sources that are not required to submit dispatch offers or follow dispatch instructions from the Australian Energy Market Operator. These include small scale rooftop PV systems, some wind and hydro generators and embedded generators connected to distribution networks.
QLD	Queensland
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
REMMA	Renewable Energy Market Model Australia
RET	Renewable Energy Target
SA	South Australia

Acronym	Definition
SEA	Southeast Australia
SMC	Safeguard Mechanism Credit, a tradeable emissions reduction credit introduced under Australia's reformed Safeguard Mechanism, designed to incentivise large industrial facilities to reduce greenhouse gas emissions below government-set baselines.
SWP	Southwest Pipeline, a key component of the Victorian Transmission System for gas
TRAM	Thermal Retirement Assessment Model
TOU	Time of Use
US	United States
VIC	Victoria
VNI	Victoria - New South Wales Interconnector
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital
WEM	Wholesale Energy Market in the south-west of Western Australia

1. Why carbon pricing matters now

Australia's energy transition is entering a critical phase. The current policy landscape risks becoming fragmented with the Large-scale Renewable Energy Target (LRET) and the Capacity Investment Scheme (CIS) expiring in 2030, and post-2030 market settings still evolving. At the same time, the electricity sector faces rising demand from electrification, accelerating coal retirements, and the imperative to meet legislated climate targets—namely, a 43% reduction in emissions by 2030 and net zero by 2050[1]. In this context, carbon pricing offers a coherent, technology-neutral mechanism to guide investment, incentivise emissions reduction, and align market behaviour with national climate goals.

This report, commissioned by the Grattan Institute (Grattan), explores a carbon pricing approach that could reset Australia's energy policy pathway: a sector-wide Emissions Intensity Scheme based on the Safeguard Mechanism. This is an approach that Australia has seen before.

We have assessed the feasibility and impact of this mechanism under carbon budgets consistent with achieving Australia's legislated emissions reduction targets in scenarios where the world acts to limit global warming to below 1.5°C and below 2°C, as defined by the Climate Change Authority, using energy market modelling. The aim is to provide evidence-based insights into how carbon pricing can support a more predictable, efficient, and credible transition for Australia's electricity markets.

[1] This modelling was conducted prior to the 2035 emissions reduction target announcement, and this target is therefore not included in the scope of works.

2. Safeguard Mechanism

The Safeguard Mechanism is Australia's primary carbon pricing tool for large industrial emitters. It applies to facilities across sectors such as mining, oil and gas, manufacturing, transport, and waste. Each facility is assigned an annual emissions baseline, calculated using its production level and an emissions intensity factor. These baselines are scaled using an emission reduction contribution which declines by 4.9 percentage points per year to support Australia's legislated targets of a 43% reduction in emissions by 2030 (from 2005 levels) and net zero by 2050.

Facilities that emit below their baseline earn Safeguard Mechanism Credits (SMCs), which can be banked, traded, or borrowed. Facilities exceeding their baseline must surrender SMCs or purchase Australian Carbon Credit Units (ACCUs), which represent one tonne of CO_2-e avoided or removed. ACCUs are generally more expensive due to their broader applicability. Market dynamics influence both prices: a surplus of SMCs lowers demand for ACCUs, while scarcity drives ACCU prices higher. As of mid-2025, ACCUs are valued at approximately \$36 and SMCs at \$35[2].

In this modelling the Safeguard Mechanism was extended to the electricity sector, with a sector-wide emissions baseline. ACCUs are not included in the modelling, as discussed in Section 4.2. The key policy design features of this extended Safeguard Mechanism are described in Table 2-1.

Table 2-1: Features of the Extended Safeguard Mechanism

Feature	Extended Safeguard Mechanism
Policy Type	Baseline-and-credit (SMCs)
Sector Coverage	Electricity sector (sector-wide baseline)
Compliance Instrument	Safeguard Mechanism Credits (SMCs)
Price Signal	Cost of compliance per t CO_2-e
Eligibility Changes	Applies a single sector-wide baseline
Revenue Source	Market-driven investment response
Market Behaviour Assumption	Rational response to declining baseline
Abatement Pathway	Mix of fuel switching, renewables, and generator efficiency improvements

[2] Demand Manager, Certificate Prices, at https://demandmanager.com.au/graphs/new_prices.php

3. Modelling approach

Grattan requested an Australia-wide study, requiring coverage of multiple grids including the National Electricity Market which covers eastern and southern Australia (NEM), The Wholesale Electricity Market which covers south-west Western Australia (WEM), the North West Interconnected System which covers a non-unified grid in the Pilbara region of north-west Western Australia (NWIS), the Darwin-Katherine Interconnected System which covers the area between Darwin and Katherine in the Northern Territory (DKIS), and the Mt Isa grid.

This study used **Strategist** to assess the impact of carbon pricing mechanisms on Australia's combined electricity market. Strategist is a licensed dynamic programming tool used to simulate each electricity market. It identifies least-cost capacity expansion and dispatch, factoring in fuel costs, technology efficiencies, capital costs (of generation, storage, and transmission), and emissions intensity. It operates over long-term horizons using typical weather conditions (50% Probability of Exceedance, PoE). Strategist is complemented by use of the following tools, developed in-house:

- **REMMA** (Renewable Energy Market Modelling and Assessment): A tool focused on renewable energy dynamics. It evaluates the profitability of renewable generators under different market scenarios and complements Strategist by providing detailed insights into renewable portfolios.
- **TRAM** (Thermal Retirement Assessment Model): A tool focused on thermal energy dynamics. It evaluates the economic viability and retirement timing of thermal generators based on profitability, age, technical characteristics and market conditions.

The modelling approach considers electricity demand forecasts, fuel and technology costs, policy settings, and carbon budgets aligned with acting to limit global warming to below 1.5°C and below 2°C as inputs, as well as market structure and incumbent behaviour. Following a simulation run, the models provide outputs that include generation and interconnector flows, market costs and system resource costs (including capital and operating costs of generation and transmission), spot prices by state, and green certificate prices.

Further detail on the modelling approach is provided in Appendix A.

3.1 Modelling Assumptions

Jacobs developed market models to identify least-cost development pathways under various policy scenarios. Key assumptions include:

- **Demand and Technology**: Based on regional forecasts and CSIRO GenCost 2023-24 data.
- **Policy Foresight**: Assumes perfect foresight and full credibility of policies announced in 2026 and implemented from 2030, with minimal anticipatory action from 2029.
- **Capacity Planning**: New capacity is added to meet reserve margins, including demand-side response.
- **Reliability Standard:** The model incorporates loss of load, energy not served, and reserve margin to assess the quality of supply. The reliability standard is enforced (in all scenarios and temperature constraints) by limiting the maximum energy not served to 0.002%, consistent with planning criteria commonly adopted by system operators.
- **Generator Behaviour**: Generators act rationally, retiring uneconomic assets and bidding based on cost.
- **Renewable Entry**: Limited by profitability; excessive zero/negative price periods prevent new entry and trigger retirements.
- **Price Formation**: Long-term prices are capped at new entry cost; short-term prices vary with market dynamics.
- **Transmission**: Includes upgrades to relieve constraints and enable inter-regional flows.
- **Simplifications**: Ramp rates, start-up costs, and second-round economic impacts are excluded.

- **Policy horizon**: The modelling period is 2025 to 2050, with the carbon pricing options active from 2030.

3.2 Retail price modelling

Acceptance of any carbon pricing policy will depend heavily on its perceived and actual impact across a range of stakeholders, particularly electricity consumers. In Australia, electricity is considered an essential service, and even modest price increases can provoke strong public and political responses. This sensitivity is amplified by the fact that electricity bills are a visible and recurring cost for households and businesses, making retail price impacts a key determinant of public support.

For policymakers, understanding how carbon pricing mechanisms translate into retail prices is critical. Retail prices are shaped not only by wholesale market dynamics but also by certificate costs, network charges, and retail margins. Policies that introduce volatility—such as those relying heavily on certificate markets—can complicate contracting and risk management for retailers, potentially leading to higher costs passed on to consumers.

Moreover, price impacts are not uniform across regions or customer types. Vulnerable households, energy-intensive industries, and small businesses may experience disproportionate effects. As such, policy design must consider not just average price outcomes, but also distributional impacts and the availability of mitigation measures (e.g. rebates, targeted support, or complementary investment schemes).

Ultimately, retail price outcomes are a critical lens through which a carbon pricing policy will be judged. Transparent modelling, clear communication, and proactive engagement with stakeholders are essential to building trust and ensuring successful implementation.

Jacobs' retail price projection framework builds on our wholesale price forecasts by incorporating a comprehensive set of cost components that influence final retail prices. This methodology has been applied in publicly available reports for AEMO and other clients to support demand forecasting and market analysis.

The approach includes:

- **Network Charges**: Regulated costs associated with electricity transmission and distribution infrastructure.
- **Retailer Operating Costs and Margins**: Costs incurred by retailers for customer service, billing, and business operations, along with a margin to ensure commercial viability.
- **Policy and Scheme Costs**: Costs arising from government programs such as renewable energy targets, energy efficiency policies, and other regulatory obligations.
- **Loss Factors**: Adjustments for energy lost during transmission and distribution, which vary by location and network configuration.
- **Risk Premiums**: Allowances for market and operational risks that retailer's factor into pricing.
- **Retail Contracting Practices**: Retailers typically hedge their exposure to wholesale price volatility through forward contracting. This practice smooths out short-term fluctuations in wholesale prices, resulting in more stable retail prices over time. However, it also means that retail prices may not immediately reflect sharp movements in wholesale markets, and a smoother forward retail price book will result from even quite volatile wholesale price projections.

The retail price projections quoted in this work will vary regionally, but we will only report results for New South Wales given its central location and large population base within the largest grid (the NEM) in Australia. Our team has collected all relevant data to calculate the retail price using publicly available sources.

3.3 Interpretation of modelling outcomes

This modelling exercise is designed to provide insights into the potential impacts of alternative carbon pricing policies under defined emissions constraints. It uses standard, long-established methods and focuses on comparative performance rather than short-term operational dynamics.

Key assumptions and limitations include:

- **Simplifications**: The model excludes short-term operational features such as ramp rate constraints and start-up costs for thermal plants. These are considered negligible over the long-term horizon (2025–2050).
- **Perfect market foresight**. The model assumes perfect market foresight.
- **Credible policy implementation**. The model assumes credible policy signals that are effectively implemented.
- **Economic scope**. Indirect or second-round economic impacts are not included.
- **Construction Bottlenecks**: Many of the policies result in rapid construction to replace the coal fleet in a short space of time. In practice this rapid construction may increase the price of inputs due to 'bottlenecks' in construction. As these increases would be reasonably uniform across scenarios and small relative to the large overall levels of investment across the scenarios, they were not estimated here.
- **Policy Horizon**: The policy is assumed to be announced in 2026 and commence in 2030. The modelling covers 2025–2050, without accounting for policy evolution beyond 2050. It is possible that the policy may evolve over time as attention is given to meeting emissions constraints beyond 2050. Further, it is possible that reaction times for the policy could take longer than 4 years.
- **Carbon budgets:** The carbon budgets are fixed for 2025–2050, based on Climate Change Authority guidance.
- **Demand and Technology Sensitivity**: Assumptions around electricity demand and technology costs are critical to outcomes. For example, the modelling does not include some potential future costs that may affect coal-fired generation such as social costs and random events (health and safety issues, old machines' parts that are no longer produced, etc.)
- **Uncertainty**: Results become increasingly uncertain over time and should be interpreted as illustrative projections, not forecasts.
- **Perfect Foresight**: The modelling assumes perfect foresight with future trends in key assumptions known with certainty. Investment decisions, for example, are made with complete knowledge of future fuel and capital costs. However, future trends in key assumptions are not known and investors consider the uncertainties when making their investment decisions.

4. Scenario design

Jacobs modelled three scenarios for the future. These scenarios were created based on the aim to measure the effects of the carbon pricing model with different (measurable) emissions reductions. The scenarios are as follows:

- **Reference case**. A reference scenario where no carbon pricing mechanism is implemented.
- **Extended Safeguard Mechanism – 1.5 °C**. An extended Safeguard Mechanism with a carbon emissions budget corresponding to action limiting global warming to below 1.5 °C.
- **Extended Safeguard Mechanism – 2 °C**. An extended Safeguard Mechanism with a carbon emissions trajectory corresponding to action limiting global warming to below 2 °C.

4.1 Carbon budgets and how they interact with the Safeguard Mechanism

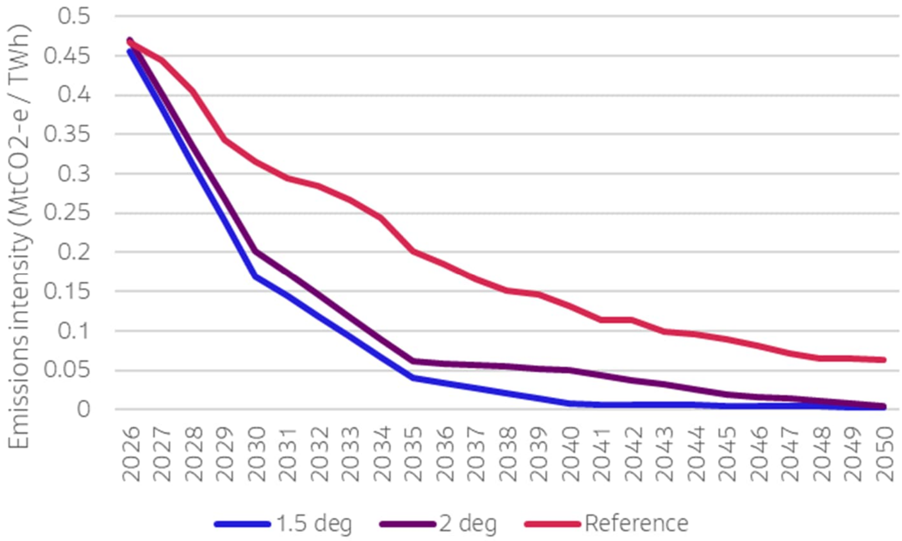
The carbon budgets used were sourced from the Climate Change Authority (CCA), specifically the Modelling Sectoral Pathways to Net Zero Emissions report commissioned from the CSIRO in August 2024. The carbon budgets were calculated from the forecast demand from the reference case, multiplied by the emissions intensities from the CCA. The resulting Australian carbon budget for the electricity sector corresponding to 1.5 degrees of global warming is 719 MtCO2-e, from 2025 to 2050. The carbon budget for the electricity sector corresponding to 2 degrees of global warming is 917 MtCO2-e, from 2025 to 2050.

Although announced in 2026, we assume the extended Safeguard Mechanism only comes into effect from 2031. Nonetheless, the scheme is market-driven, and assume the market has foresight of this policy. The result is that the sectoral emissions follow the reference case trajectory until at least 2027, because we do not anticipate time for any action before then. In the couple of years pre-2030 in the case of a Safeguard Mechanism extension being announced, the model assumes the market will anticipate the scheme being extended to the electricity sector after 2030 leading to slightly increased emissions abatement pre-2030 than in the reference case.

The carbon budgets constrain the capacity buildout and generation (towards lower emission options) of all scenarios except the Reference Case. The model is iterated until the total emissions from 2025 to 2050 are at or below the carbon budget for that scenario, using the Safeguard Mechanism as the principal policy lever.

The extended Safeguard Mechanism operates like the existing Safeguard Mechanism, except that the electricity sector is subject to a sector-wide emissions baseline. This varies from the existing Safeguard Mechanism where each eligible facility in the industrial sector has its own emissions baseline. The sector-wide emissions baseline is calculated based on the carbon budget in each scenario.

Figure 4-1 Emissions intensity trajectory[3]



Source: Jacobs' analysis and Climate Change Authority

4.2 Exclusions

This model is aimed at addressing the impacts of carbon pricing on the electricity sector nationally. A rooftop PV capacity trajectory to 2050 is included in model inputs, which is sourced from Jacobs' assumptions, described in Section B.1.1.3. This rooftop PV forecast does not vary between scenarios.

As described in Section 2, ACCUs can be purchased under the current Safeguard Mechanism in the industrial sector in lieu of surrendering SMCs. In this model ACCUs are excluded: the banking and borrowing of SMCs is allowed, so generators who exceed the emissions baseline must surrender SMCs.

[3] The emissions trajectories for the 1.5 degree and 2 degree warming cases are indicative, as the modelling used the cumulative emissions up to the carbon budget.

5. Reference scenario

The reference scenario is used as the basis of comparison for the policy options. The scenario is based on a world where current policy setting around energy markets and carbon mitigation remain in place. There is no new policy post 2030 to mitigate carbon emissions in the sector.

Specific scenario assumptions include:

- The LRET remains in place but expires as legislated at the end of 2030.
- The CIS scheme is used to fund renewable energy and energy storage projects, funding 23 GW of new renewable energy capacity and 9 GW of energy storage capacity in the period to 2030 across the NEM, WEM and DKIS. Apart from projects already successful under the scheme tenders, we allow the model to choose what technologies makes up the rest of the capacity required. Additional capacity is based on the model's selection of the least cost mix of technologies[4].
- State energy policies are not considered.
- Announced retirement dates are met[5] (despite permitted earlier retirement for economic reasons).

All other assumptions are as listed in Section 3.

5.1 Capacity outcomes

Despite there being no direct renewable support policy, the level of renewable energy capacity continues to grow in the major grid systems. However, thermal capacity including coal capacity is projected to remain in operation over the modelling horizon. Some coal plants continue to operate in the NEM until 2046, and one coal plant in the WEM is projected to continue to operate until 2050[6].

Wind and solar capacity are projected to dominate the capacity mix in the long term in the NEM and the WEM. Wind and solar account for around two thirds of installed capacity in 2050 in the NEM and just under half the installed capacity in the WEM. For the other grids, the level of renewable capacity comprises around 28% in the DKIS (all of it solar capacity) and less than 10% of installed capacity in the NWIS and Mt Isa grids.

Energy storage comprises a growing proportion of capacity in the NEM and the WEM, comprising around one quarter of total capacity in 2050.

Natural gas-based generation (including hydrogen ready capacity) is projected to continue to play an important role, comprising in 2050 5% of capacity in the NEM, 25% in the DKIS, nearly 30% in the WEM and over 90% in the other grids.

Coal based generation, as a proportion of total generation is expected to decline as coal plant reach the end of their technical life and as remaining plant shift to a mid-merit duty. In the NEM coal generation steadily declines. In the WEM, coal generation declines as plant retires but generation at the remaining plant stays relatively steady.

Gas based generation is projected to remain an important component of total generation, comprising 30% to 90% of total generation in the grids other than the NEM. In the NEM gas generation comprises less than 5% of total generation, but it still has an important role for back up purposes.

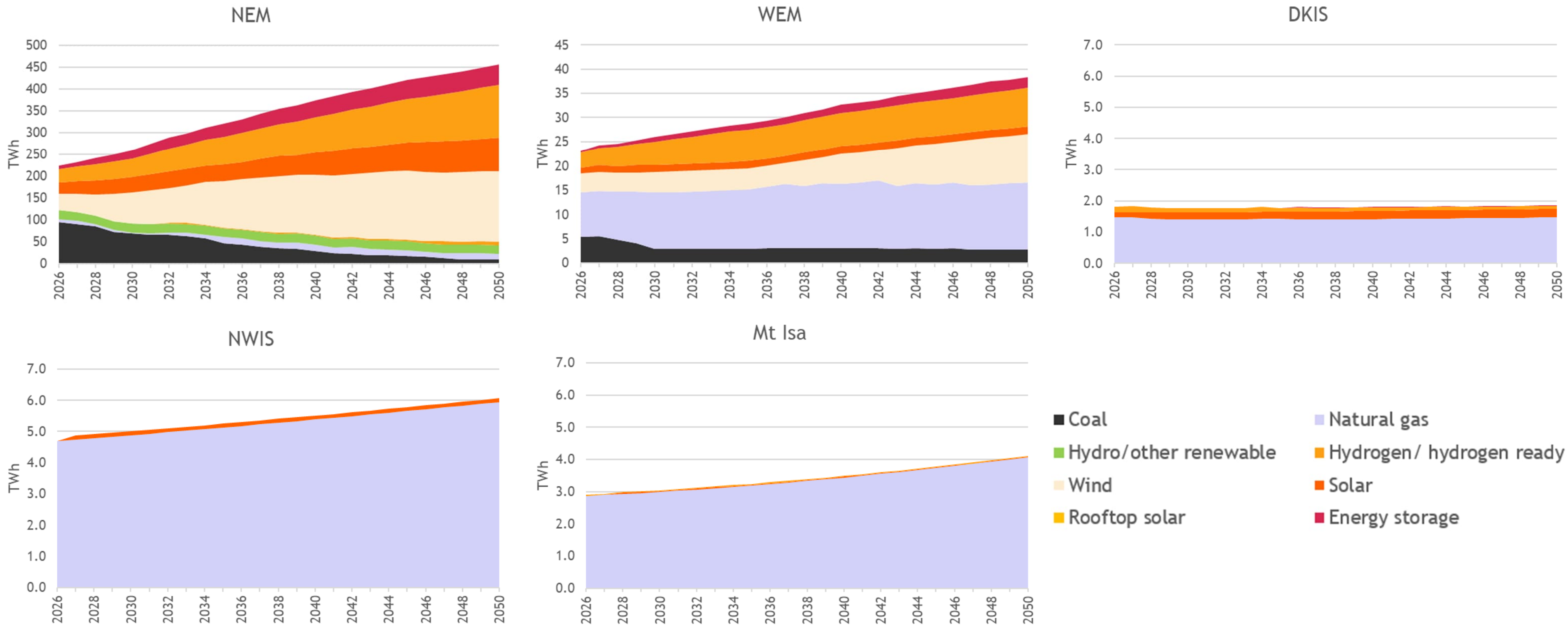
[4] Where least cost is that mix of technologies that minimises system costs over the modelling period to 2060.

[5] This does not include the intended earlier retirement of Gladstone Power Station which was announced after the time of modelling.

[6] The result for continuing operation of coal in the WEM should be treated with some caution as it hinges on the coal mine remaining viable supplying a limited customer base.

Figure 5-1. Capacity mix, reference scenario

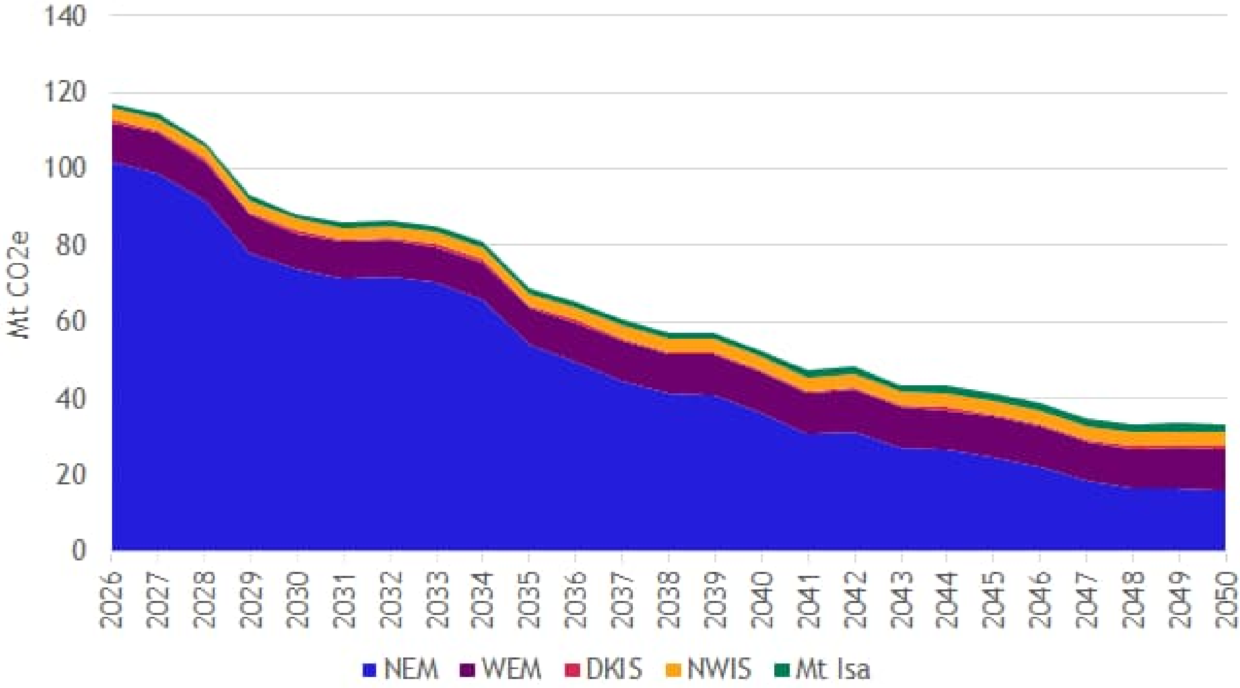
Figure 5-2. Generation mix, reference scenario



5.2 Emissions

Under the reference scenario assumptions, emissions are projected to fall in the period to 2050. This is mainly due to reducing emissions in the NEM as the coal plant retire when they reach the end of their economic or technical life (and is largely replaced by renewable energy and storge capacity). For other grids, there is some fall off in emissions to 2030, particularly in the WEM, but thereafter emissions remain relatively stable as gas-fired generation levels remain stable.

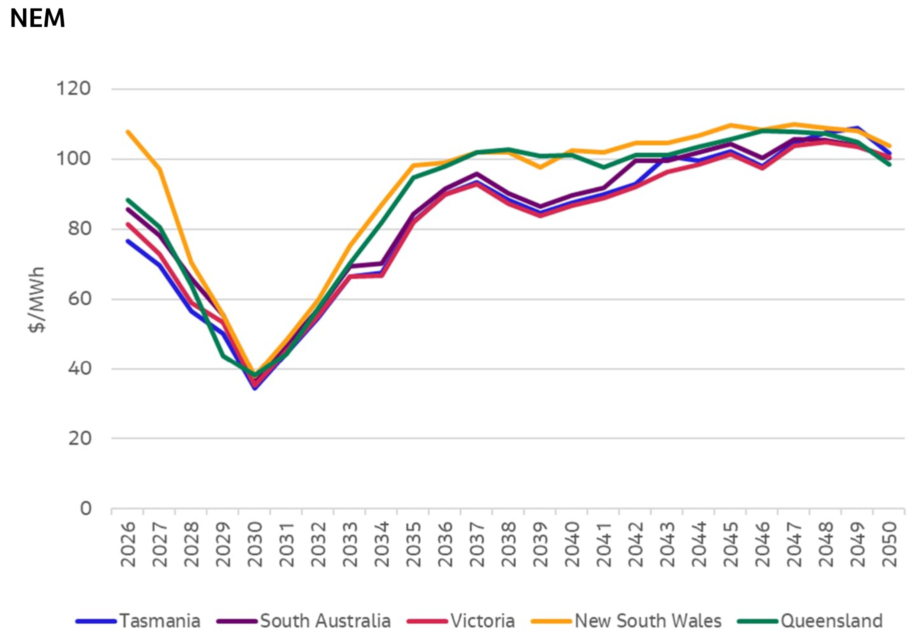
Figure 5-3. Projected emissions, reference scenario

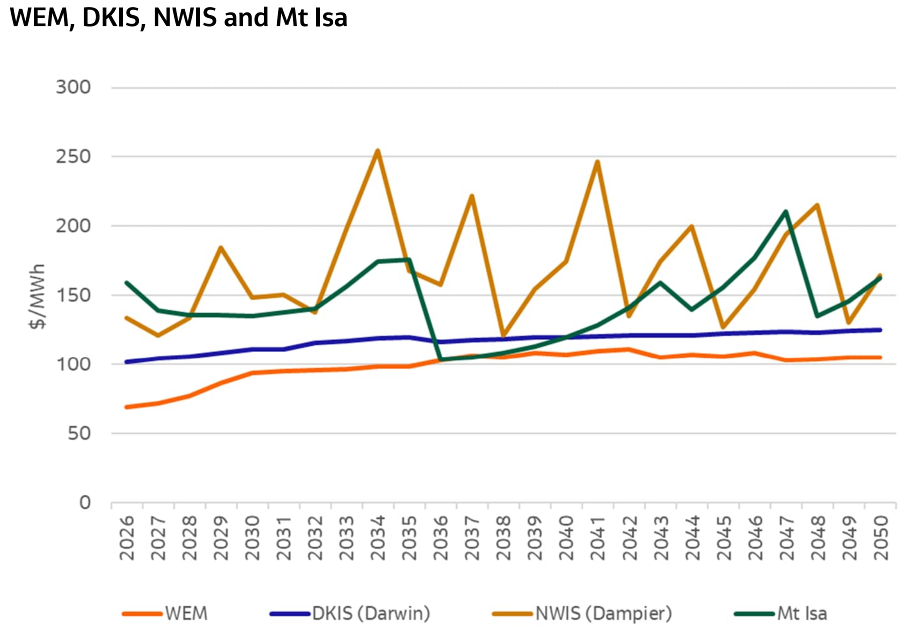


5.3 Wholesale prices

The expected wholesale spot prices for each Australian market under the Reference Case are displayed in Figure 5-4.

Figure 5-4. NEM, WEM, NWIS, DKIS and Mt Isa time-weighted prices, Reference Case



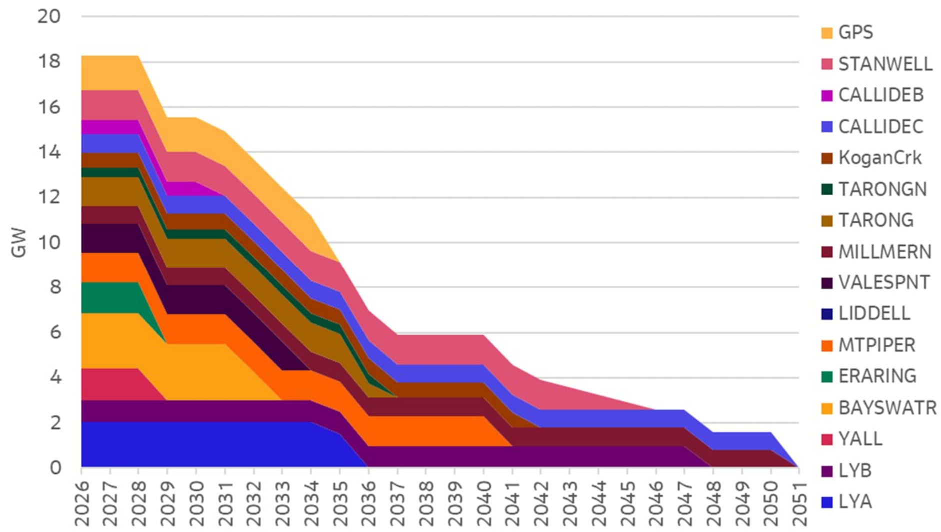


Source: Jacobs' analysis

From 2026, annual time-weighted prices (TWP) for the NEM regions would decline by 10-17% on a year-by-year basis, with Queensland's TWP declining to $38/MWh. From the mid-2020s, the expanded Capacity Investment Scheme (CIS) will secure up to 23 GW of variable renewable capacity by 2030, underwritten by the Federal Government through a secured revenue floor and ceiling. This additional renewable supply will sufficiently meet the growing energy consumption demand caused by increasing industrial, electrification, and EV charging load. Together with falling gas prices, wholesale electricity prices are therefore expected to reduce between 2026 to 2030.

After 2030, the end of the CIS and the start of a steady precession of coal retirements throughout the 2030s are drivers for wholesale price increases in 2030-2035. The entrance of offshore wind in Victoria in the midlate 2030s reduces prices for southern states, otherwise prices for the NEM revert to the price of new-entrant generation in the long-term.

Figure 5-5. NEM coal retirement schedule, Reference case



Across the rest of Australia, wholesale time-weighted electricity prices are strongly influenced by the generation mix in each region:

- In the WEM and DKIS, new generation is primarily solar and battery storage, with minimal baseload retirements during the reporting period.
- In contrast, the NWIS and Mt Isa are seeing the entry of new gas-fired plants to meet rising demand. This initially lowers prices, but as demand continues to grow, prices rise again until further supply is added.

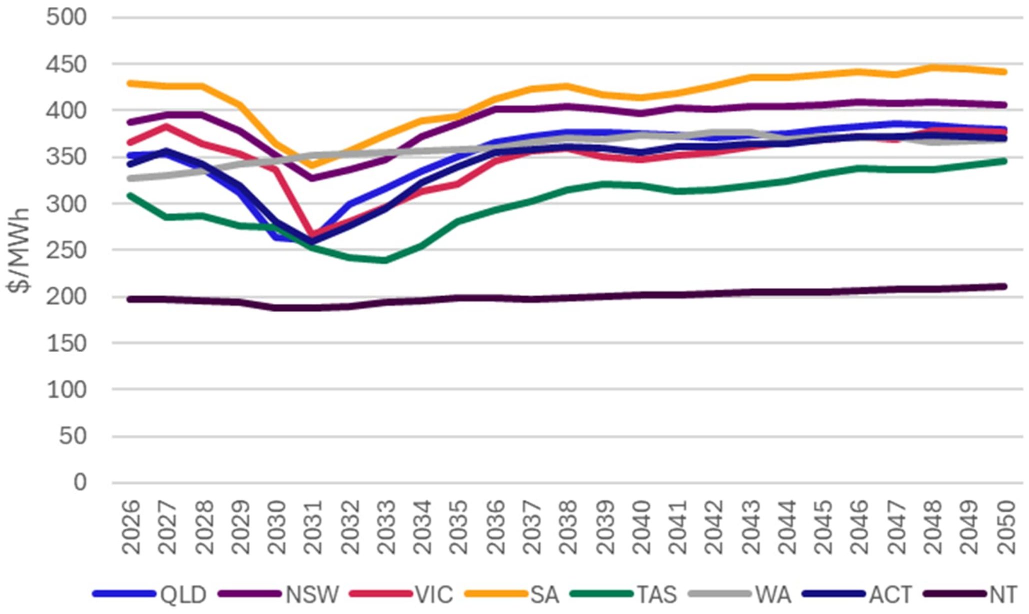
5.4 Retail prices

The expected residential retail prices for each Australian state and territory under the Reference Case are displayed in Figure 5-6. Retail prices are calculated from several inputs including wholesale prices, network charges[7], green schemes, white schemes, feed-in tariffs, market charges, retailer costs and margins, and GST.

Apart from network charges and wholesale prices which provide a significant contribution to retail prices, most of these components are small, and in some cases such as green scheme costs, declining and finishing by 2030. Therefore, the retail price trajectory largely resembles that of wholesale prices, especially after 2030.

[7] Includes additional charges for transmission and renewable energy zones. Base network charges follow guidance from the relevant tariff structure statement and thereafter are assumed to be constant.

Figure 5-6. Residential retail prices, Reference case



6. Results and Insights

This section presents the Safeguard Mechanism scenario results against the reference scenario under the two carbon budgets (limiting global warming to 1.5°C and 2°C respectively).

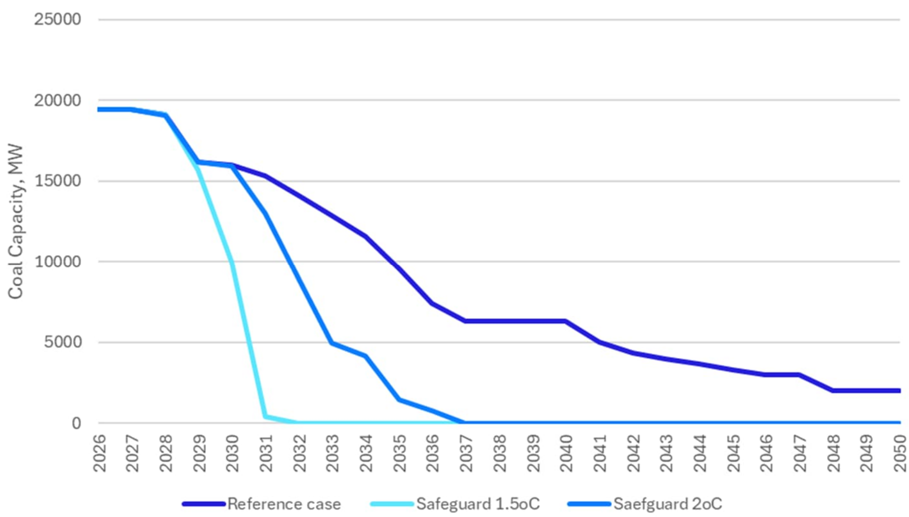
We focus on four key outputs: capacity buildout & generation, emissions trajectories, resource costs and wholesale & retail prices.

6.1 Capacity buildout and emissions trajectory

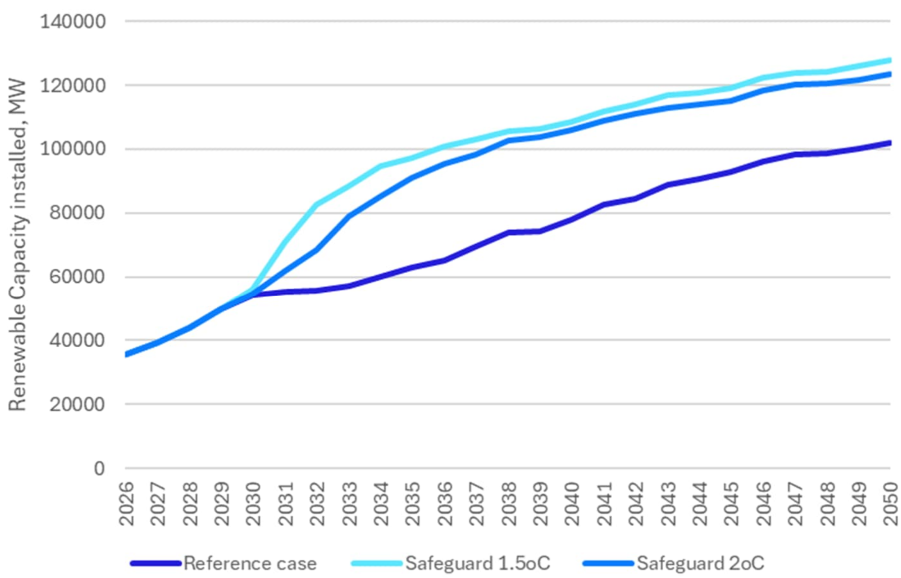
Figure 6-1 compares the build out of renewable generation and the retirement progress of coal plants under each warming scenario. Essentially the tighter carbon budget from the 1.5°C warming scenario results in earlier and larger build out of renewable generation, and subsequently faster retirement of coal generation capacity. With significant amounts of other generation options, coal plants become unprofitable, which leads to earlier retirement.

Figure 6-1 Comparison of capacity build out plans

Coal capacity



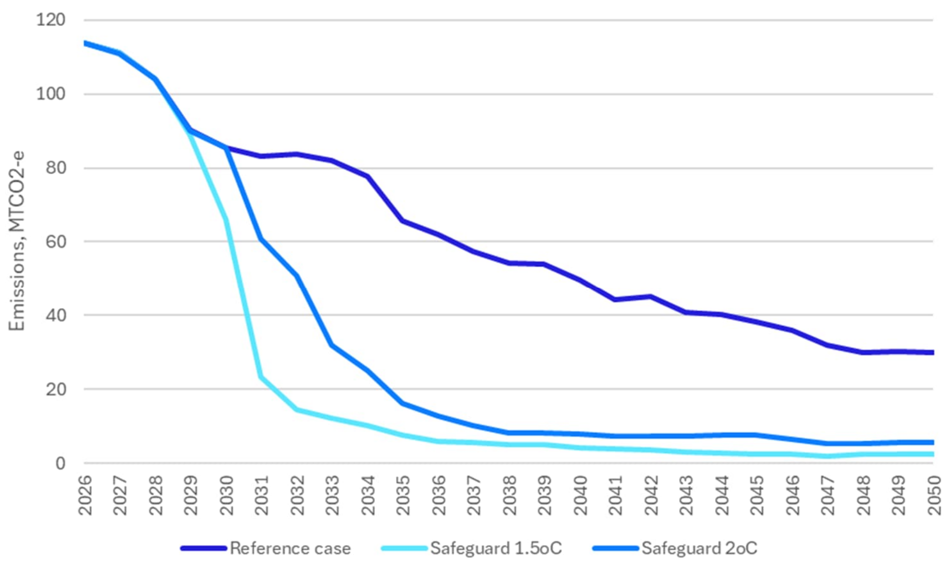
Renewable Generation Capacity



Source: Jacobs' analysis

The faster retirement of coal directly impacts emissions, as displayed in Figure 6-2 which compares emissions trajectories for both scenarios.

Figure 6-2 Comparison of emissions trajectories



Source: Jacobs' analysis

6.2 Wholesale and retail prices

Figure 6-3 and Figure 6-4 display the forecast real wholesale and retail prices respectively for both warming scenarios, calculated as a demand weighted average across all regions.

Deep decarbonisation is likely to increase prices in the 1.5°C warming scenario. In the 2°C warming scenario there is much less variation in prices between the carbon policy scenario and the reference case, particularly in the retail prices.

The spike in wholesale electricity prices from the early 2030s in the extended Safeguard Mechanism scenarios (particularly the 1.5°C warming scenario) is driven by a rapid coal retirement schedule with no/limited policy anticipation assumed in the late 2020s to build sufficient renewable capacity to make up the lost coal supply. A more gradual coal retirement schedule in the 2°C warming scenario reduces the effect on wholesale prices in the early 2030s.

As a result of the significant loss of baseload in the 1.5°C warming scenario, an increase of gas generation must occur until sufficient renewable capacity is built (mid-2030s). Up to this period, the uptake of renewable projects is constrained by regulatory and planning delays (such as from lengthy environmental impact assessments), and social licensing issues (including community pushback against windfarms and transmission projects). It should also be noted that hydrogen-ready gas plants are assumed to still have a fuel blend of at least 90% fossil gas before 2035[8]. The effect this has on price is magnified during this period because of the introduction of the Safeguard Mechanism to the electricity sector (creating a carbon price) which increases the bid price of thermal generation (particularly for peaking gas which bids at several multiples above its

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[8] We have not modelled changes in hydrogen demand because of changes in hydrogen-ready gas plant generation between the scenarios. We assume that these plants are co-developed with renewable generation and hydrogen storage sufficient to supply their hydrogen fuel demand and minimize the net impact on hydrogen and electricity demand. Intermittent shortfalls in local hydrogen supply are assumed to be balanced with natural gas.

SRMC). The carbon price is a bigger driver (proportionately speaking) in the price spike seen in the 2°C scenario, where gas generation has still increased (relative to the reference case), but is not as pronounced.

In the long-term, under the assumption of mean reversion, wholesale electricity prices converge to the long-run marginal cost of the next additional generation capacity required. In the short to medium-term, prices may diverge from the long-run marginal cost, due to supply chain constraints which limit the buildout of required capacity (e.g. environmental approval and construction delays, or social licensing issues), or government incentives/targets underwriting a greater level of capacity than the market deems economically sound (without government intervention). By the mid-2030s, wholesale electricity prices in both the Reference, and Safeguard 2°C scenario both converge to the long-run marginal cost of new entrant generation. In the Safeguard 1.5°C scenario, the carbon price is higher (versus 2°C) to achieve greater emissions reductions, and more hydrogen-ready gas capacity is needed for firming due to the earlier coal retirements. Consequentially, the long-run cost of new-entrant generation is higher (than both other scenarios), reflective of the higher capital costs attributed to hydrogen-ready gas plants, and higher abatement costs associated with fossil gas use. This leads to wholesale electricity prices increasing to a higher level in the Safeguard 1.5°C scenario in the long-term, before converging to similar levels in the Reference and Safeguard 2°C scenario by the late 2040s after no additional (relative to the Reference case) hydrogen-ready gas plant is needed.

Retail prices for the extended Safeguard Mechanism scenarios are driven predominantly by the behaviour of wholesale prices throughout the forecast period.

Figure 6-3 Comparison of wholesale price path projections

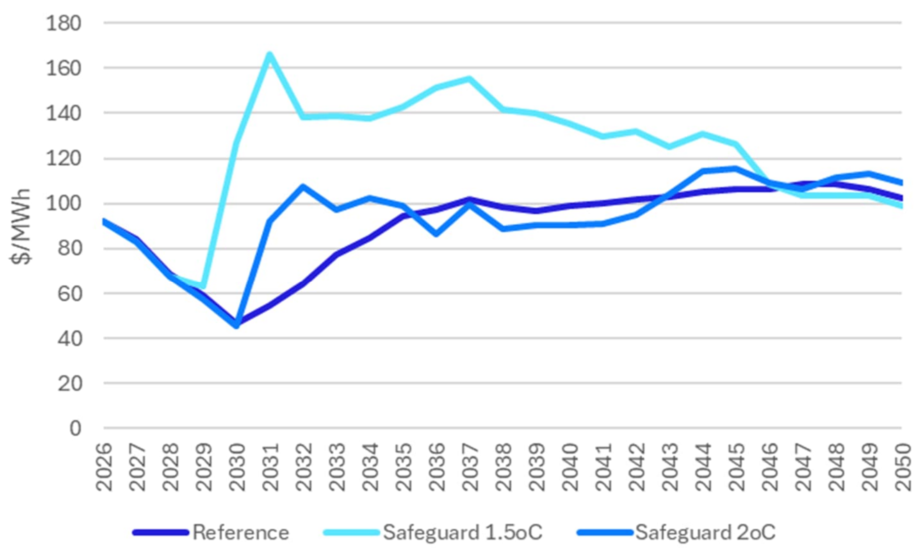
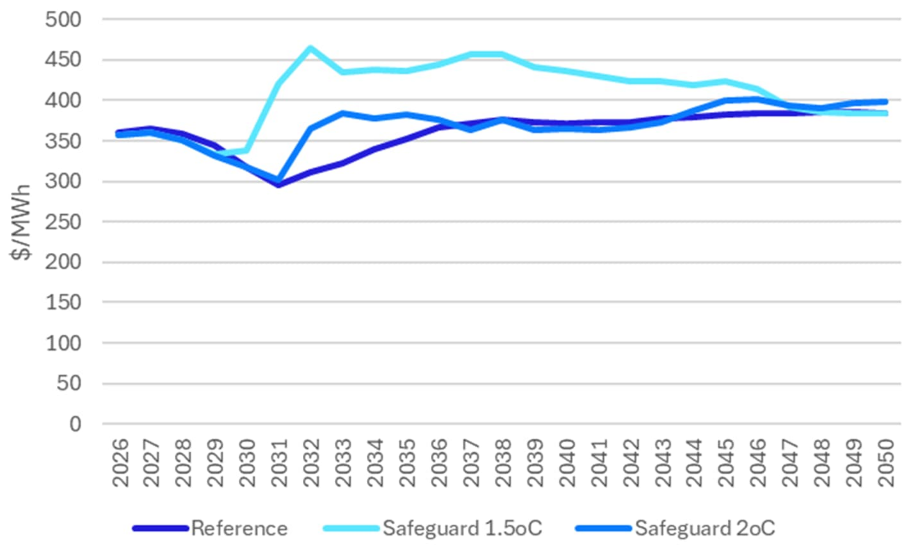


Figure 6-4 Comparison of retail price path projections



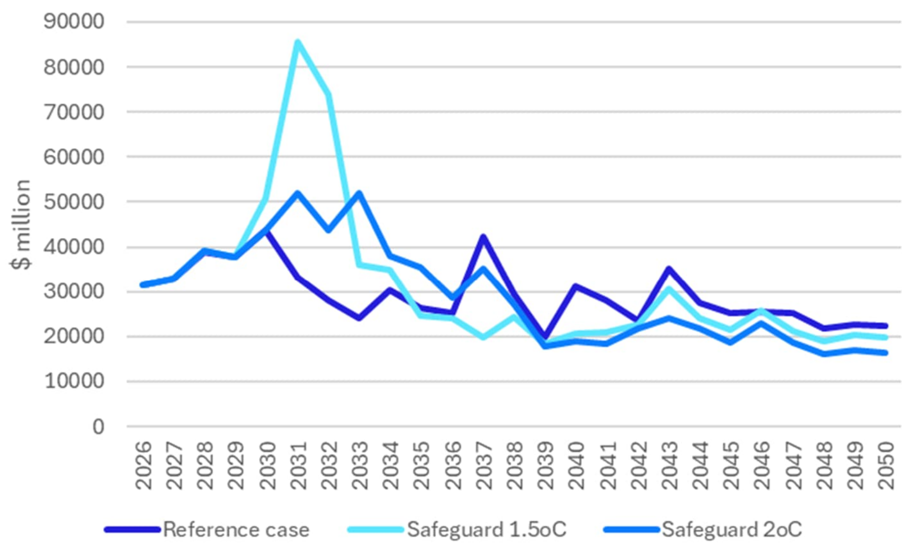
Source: Jacobs' analysis

6.3 System costs and abatement efficiency

Abatement cost under 1.5ºC warming was calculated at $134 / t CO2-e, while the abatement cost under 2ºC warming was calculated at $87 / t CO2-e, implying stronger abatement efficiency under the reduced emissions target. Abatement cost was calculated applying a discount rate of 7.4% (a Jacobs assumption on the Weighted Average Cost of Capital) to future years as part of a net present value calculation.

This is largely because of a large increase in resource costs for the 1.5ºC warming scenario in the early 2030s, caused by a rapid capacity build in these years required to offset the decrease of coal capacity. This spike is not present in the 2ºC scenario since the capacity build is not as rapid under the larger carbon budget. The rapid coal retirements also front-load firm capacity installation, reducing the proportion installed in later years.

Figure 6-5 Comparison of resource costs



Source: Jacobs' analysis

7. Discussion and insights

The focus on the study is to understand the impact of a carbon pricing mechanism to operate on Australia's electricity systems from 2031 onwards, after the LRET scheme and CIS investments expire. The carbon pricing mechanism is aimed at addressing the externality caused by the emissions of greenhouse gases and provide signals for investment in and use of low emission generation to meet our national emission reduction targets.

The relative impacts in this study were based on assessing the impacts of and obtaining insights on the following metrics:

- Comparing cost efficiency
- Technology diversity
- Market behaviour
- Investor certainty
- Retail price impacts

7.1 Climate Ambition

Our analysis indicates that achieving the more ambitious 1.5°C climate target requires a significantly accelerated transition across multiple dimensions of the energy system. Specifically, this pathway demands:

- Early and large-scale retirement of coal-fired generation, well ahead of current trajectories.
- Rapid and sustained deployment of renewable energy capacity, particularly in the 2030s; between 2031 and 2035, more than 9 GW of large-scale renewable energy and storage capacity will need to be installed annually on average.
- A strong and credible carbon pricing signal to drive investment and operational decisions.
- Likely average retail price increases of 13% on average relative to the reference case across the projection horizon.

However, recent experience has demonstrated that delivering multiple large-scale infrastructure projects in parallel—such as transmission upgrades, renewable buildout, and firming capacity—requires a high degree of policy coordination, regulatory alignment, and investment certainty. These conditions are not consistently present in the current policy landscape.

As a result, while the technical requirements for accelerated coal retirement are well understood, the practical feasibility of replacing legacy infrastructure at the necessary pace remains uncertain. Without clear and coordinated policy action, including alignment between federal and state governments, the risk of delays, cost overruns, and underinvestment increases—potentially jeopardising Australia's ability to meet its Paris-aligned targets.

The alternative carbon budget, set at 2°C, requires a slower coal phase-out, moderate renewable growth and less aggressive pricing.

7.2 Regional abatement challenges

Australia's decarbonisation efforts are unevenly distributed across its electricity grids due to differences in geography, resource availability, and infrastructure maturity.

- **Major Grids (NEM and WEM).** The National Electricity Market (NEM) and Wholesale Electricity Market (WEM) account for most of the abatement activity due to their scale and renewable resource access. The NEM benefits from high renewable potential, particularly wind and solar, supported by pumped hydro and seasonal gas for firming. The WEM has moderate renewable potential, with battery energy storage systems (BESS) and gas playing a key backup role.

- **Smaller and Isolated Grids (NWIS, DKIS, Mt Isa).** These grids face limited renewable potential, often constrained by geography or demand profiles. They require long-duration storage solutions (e.g., 8–10-hour BESS) or continued reliance on gas, which may result in higher costs and slower transitions. For example, the Northwest Interconnected System (NWIS) and Mt Isa grids are heavily reliant on gas, while the Darwin–Katherine Interconnected System (DKIS) is largely solar-dependent but still requires gas backup.

These factors lend themselves to a more technology neutral approach to policy setting.

7.3 Technology Mix and Equity Considerations in Australia's Decarbonisation Pathway

Australia’s decarbonisation strategy must account for the regional disparities in infrastructure, resource availability, and policy mechanisms. The Safeguard Mechanism allows for fuel switching, such as transitioning from coal to more efficient gas-fired generation. This flexibility may disproportionately benefit regions and industries with existing gas infrastructure, such as parts of Queensland, WA, and the NT. These areas can leverage existing pipelines and generation assets to reduce emissions while maintaining reliability, albeit with ongoing carbon exposure. The extended Safeguard Mechanism minimises the net cost of meeting targets, with the main reason for this being because it relies on more than one measure to bring down emissions.

7.4 Gas: Balancing Reliability and Emissions

Natural gas continues to play a pivotal role in maintaining grid reliability and system security, particularly in regions with limited renewable potential or constrained storage options. Its flexibility and dispatchability make it a valuable resource for meeting peak demand and covering extended periods of low renewable generation, especially during winter months.

However, gas-fired generation presents a clear trade-off: while it supports short-term reliability, it remains a source of carbon emissions unless paired with carbon capture and storage (CCS) or offset mechanisms. This tension underscores the need for careful policy design to ensure gas use does not undermine long-term net-zero objectives.

In the National Electricity Market (NEM), modelling indicates that 24-hour duration pumped hydro is being installed to support deep decarbonisation. Yet, even in high-renewables scenarios, gas turbines remain economically viable to cover extended renewable lulls. In contrast, smaller grids such as the Northwest Interconnected System (NWIS), Darwin–Katherine Interconnected System (DKIS), and Mt Isa rely more heavily on gas due to limited renewable diversity and storage options. In these systems, Battery Energy Storage Systems (BESS) are typically only economic up to 8-hour durations, reinforcing the need for gas-fired backup capacity.

7.5 Network Impacts

This study did not directly consider network impacts of each of the scenarios presented. However, the extended Safeguard Mechanism presents distinct implications for electricity networks across Australia.

This carbon pricing mechanism presents a gradual transition, with a diversified mix of emissions reduction approaches including fuel switching and industrial decarbonisation. This pathway disperses the pressure on transmission infrastructure, as the pace of renewable deployment is measured. The continued operation of centralised generation assets, particularly gas-fired plants, supports system stability and reduces the urgency of network adaptation. However, the extended Safeguard Mechanism may drive significant changes in industrial energy use, including electrification of processes and the emergence of new load centres. Networks will need to plan for these shifts, ensuring adequate capacity and flexibility to support evolving demand profiles.

7.6 Broader policy alignment

The Capacity Investment Scheme (CIS) is a central mechanism in Australia's energy transition, designed to de-risk investment in clean generation and firming capacity by underwriting revenue for eligible projects. Its role and effectiveness are closely tied to the broader policy environment, particularly in the case of the extended Safeguard Mechanism.

The extended Safeguard Mechanism promotes a balanced mix of emissions reduction approaches, including fuel switching and industrial decarbonisation. This results in a gradual buildout of renewables and a continued role for centralised generation, which eases immediate pressure on firming capacity. The CIS remains relevant under this pathway, but its deployment may be more targeted, supporting clean dispatchable technologies in regions with emerging reliability needs or industrial load growth. Additionally, CIS could play a strategic role in supporting electrification and hydrogen development, particularly where new demand centres arise from decarbonisation of industrial processes.

The effectiveness of CIS depends on strong alignment with other policy instruments. Coordination between federal and state schemes—such as the integration of CIS with Long-Term Energy Service Agreements (LTESAs) in New South Wales—is essential to avoid duplication and ensure efficient market outcomes. Furthermore, CIS must be integrated with network planning and emissions policy to ensure that supported projects contribute meaningfully to system needs and decarbonisation goals.

7.7 Price Effects

There are several different mechanisms to calculate the "policy costs" of each scenario, seen by different entities in the electricity market.

1. **Wholesale prices** apply to generators, retailers, and large industrial loads purchasing power directly. However, all electricity users also incur costs associated with Large-scale Generation Certificates (LGCs), so wholesale prices alone do not fully reflect the total cost impact on end users.

2. **Retail prices** apply to most consumers of electricity, including residential consumers, small and medium enterprises, commercial consumers, and small industrial loads.

3. **Resource costs** cover the capital and operating costs of generation and transmission, as well as fuel costs. These costs are seen by generators, investors, and the government, and can be used to calculate the level of investment needed to put these policies into place (such as through an abatement cost as described below).

4. **Abatement efficiency** can be calculated from resource costs and represent the level of investment required per tonne of carbon dioxide emissions saved. Abatement cost was calculated in this report as a net present value calculation.

In all the above mechanisms, the policy costs of the extended Safeguard Mechanism under the 1.5°C warming scenario are higher than the 2°C. This is unsurprising, as the rapid renewables buildout and market response required to reduce carbon emissions in the early 2030s under the 1.5°C warming scenario causes all the above costs to increase. This increase is less pronounced under the 2°C warming scenario, due to the more gradual market transition.

Resource costs are the best indicator of a policy's true economic impact, and abatement efficiency often reflects the most practical and cost-effective way to meet emissions reduction targets. However, it's also important to understand how these costs affect wholesale and retail electricity prices, as this helps anticipate how costs will be passed on to consumers. This insight can inform additional policy measures to address any unintended market consequences.

8. Conclusions

8.1 Policy Action Required to Align with Paris Agreement Goals

A key outcome of the analysis is the need for stronger emissions abatement relative to the current reference case to meet the temperature targets of the Paris Agreement—specifically limiting warming to 1.5°C or 2°C.

Despite the growth of renewable generation, many emissions-intensive generators are expected to remain operational well into the 2040s, only retiring at the end of their technical life.

Without coordinated and timely policy reform, these legacy assets risk delaying the energy transition and jeopardizing Australia's emissions targets.

By financial year 2027, the remaining carbon budget for the power sector is critically low:

- Only 376 $MtCO_2$-e left under the 1.5°C pathway
- Just 574 $MtCO_2$-e under the 2°C pathway

For context, electricity generation alone emitted 152 $MtCO_2$-e in calendar year 2024—meaning the sector could exhaust its entire budget within just a few years without decisive action [9].

8.2 Current Challenges

The policy landscape is fragmented, with misalignment between federal and state initiatives.

This fragmentation risks undermining regulatory certainty and weakening investment signals, particularly for long-term clean energy infrastructure.

8.3 Extended Safeguard Mechanism accelerates transition

Our modelling shows that carbon pricing reform, as implemented in the modelled extended Safeguard Mechanism, would accelerate the transition while maintaining system security and resilience.

Urgent carbon policy reform, such as those proposed by the Grattan Institute, could provide a more coherent framework for emissions reduction.

8.4 Meeting 1.5ºC emissions trajectory budget presents significant challenges

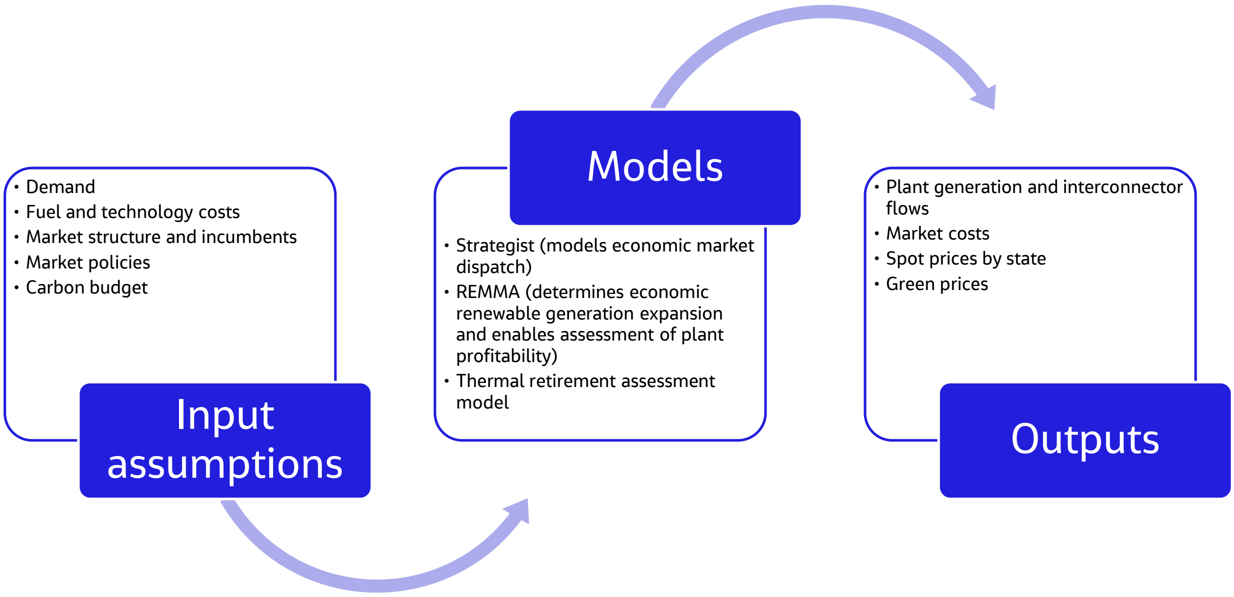
The rapid decarbonisation required to meet the 1.5ºC target within the electricity sector, given today's starting point, leads to higher wholesale and retail prices that do not return to reference cases prices until the late 2040s. Conversely, the price outcomes in the 2ºC case converge on the reference case prices ten years earlier. Similarly, the abatement cost of the 1.5ºC case and the 2ºC case are $134/t and $87/t respectively.

[9] DCCEEW - National Greenhouse Gas Inventory Quarterly Update: December 2024

Appendix A. Detailed modelling approach

Market models have been developed to determine a least cost market development plan and the likely outcome with respect to each scenario's underlying assumptions. An overview of the approach is displayed below with additional detail provided in later sections of this report.

Figure A-1. Overview of approach



The market forecasts consider regional demand forecasts, generating plant performance, timing of new generation including embedded generation, existing interconnection limits, and the potential for interconnection development. Jacobs used its Strategist and REMMA models to develop long-term time-weighted prices. Strategist models the NEM, whilst REMMA models the details of the renewable energy market.

The dynamic programming method in Strategist selects new capacity on a least-cost basis. In Jacobs' experience the model has been generally accurate in the prediction of the future generation mix, with the main deviations from predicted investment the result of:

- Economies of scale.
- Pre-emptive new entry.
- Fuel supply arrangements.
- Interconnection upgrades included in the Strategist modelling as development options in competition with new generation capacity.

Future wholesale electricity prices and related market outcomes are driven by the supply and demand balance, with long-term prices being effectively capped at the cost of new entry on the assumption that prices above this level provide economic signals for new generation to enter the market. Consequently, assumptions on the fuel costs, unit efficiencies, and capital costs of new plant and emissions intensity threshold will have a noticeable impact on long-term price forecasts. Year-to-year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power.

Negative price period prices are limited in the modelling for the following reasons:

- We model hourly demand profiles for typical weeks in each month of the projection period.

- The modelling is optimised over average weather conditions (50% probability of exceedance) so does not model outcomes for when we have warmer than normal days in winter or hotter than normal days in summer.
- Modelling includes transmission and interconnector upgrades, which will relieve network constraints and remove bottlenecks on interconnectors.
- Significant uptake of storage and EV charging (in the long-term) which means that middle of day demand is boosted.
- Continuing uptake of solar PV in our models is limited by the level of profitable entry. If we have too many zero or negative price periods, then prospective new plants may not earn enough revenue to recover capital and investment costs, and hence they do not enter the market. Similarly, if there are too many zero price periods, then eventually some incumbent thermal plants become unprofitable and are retired.

Key assumptions used in the modelling include:

- Capacity is installed to meet the target reserve margin in each region. Some of this peaking capacity may represent demand-side response rather than physical generation assets.
- Wind generation is based on observed wind power generation profiles for each region for 2019.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months.
- Infrequently used peaking resources are bid near the market price cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- The LRET target requires 33,000 GWh of renewable generation annually until 2030, and was first met in 2020.

A.1 Common assumptions to all markets

This section outlines the assumptions feeding into each modelled market, in the reference case. Model assumptions common to all markets are outlined in Table A-1.

Table A-1. Common assumptions to all markets – reference case

Assumption	Parameter	Reference case
Policy	Commonwealth Emissions Policy	State Government targets and expanded Capacity Investment Scheme drive emissions reductions to 2030. The inclusion of the amended Safeguard Mechanism commenced from 2024. Emissions reductions target of 43% over 2005 levels by 2030 is included.
Technology costs	Renewable energy generation and energy storage technology costs	Wind and solar updated to CSIRO GenCost 2023-24 (Global Post-2050 NZE scenario)
New entrant projects	Renewable energy database update (committed & existing)	Updated to include recently committed plant, fully energised projects, and relevant project delays.

A.2 Commonwealth policies

The COP26 Conference has seen major economies increase their climate ambition and the announcement of major international partnerships. The previous Australian Federal Government, prior to the recent election, presented its Long-term Emissions Reduction Plan[10] at the Conference with the announcement of an economy-wide net zero emissions target and a focus on investment in future technologies. The previous Liberal-National Government's policy remained at 26-28% emissions reductions on 2005 levels by 2030 economy wide but they did not indicate a desire to pursue strong direct emissions reduction policy. The new Labor Government's policies indicated support for decarbonisation of the economy, including agreeing with the States to change legislation to include an emission reduction objective as part of the National Electricity Law. The latter could see the emergence of policies to support decarbonisation.

The present Labor Government has legislated ambitions of 43% emissions reduction economy wide by 2030.

After 2030 we assume that a zero-emission electricity system will exist by 2050, which is achieved by market participants acting in accordance with their social license to operate to affect their retirement, investment and even dispatch decisions to meet the longer-term goals for decarbonisation.

A.2.1 Coal and gas price caps

On 9 December 2022, the Federal Government announced that a temporary, emergency 12-month cap would be imposed on domestic gas prices across the east coast, and on black coal prices for coal generators in New South Wales and Queensland. The year-long price cap on gas was $12 per GJ, which expired in December 2023, is now observed as a 'reasonable price' in the Gas Market Code, administered by the ACCC, and to be reviewed in July 2025. New South Wales and Queensland black coal prices were restricted to a ceiling price of $125 per tonne, which translates to approximately $5.44 per GJ, however both caps had expired by 30 June 2024.

A.2.2 Snowy 2.0 expansion

In 2017, the Federal Government announced a $4.5 billion plan to expand the capacity of the Snowy Hydro scheme by another 2,000 MW. Snowy 2.0 has major project status from the Federal Government. The new pump storage generator would only add capacity to the NEM, not energy.

Snowy 2.0 has experienced a range of setbacks including construction delays from bad weather and the death of a worker which paused all activities. The project has been hit by supply chain issues, labour and materials shortages, and difficult geological site conditions. These factors have led to cost blowouts and further delays in the expected commencement of the project. All scenarios assume Snowy 2.0 comes online from 2031.

A.3 Capacity Investment Scheme expansion

The Capacity Investment Scheme (CIS) was designed to provide a national framework to encourage new investment in clean dispatchable capacity, support reliability, and reduce the risk of price shocks in Australia's changing energy market.

At inception, it was expected to bring on at least $10 billion of new investment and 6 GW of clean dispatchable capacity by 2030.[11] The 6 GW figure was based on AEMO modelling from the ISP step change scenario.

The first stage of the capacity investment scheme launched in 2023 aimed to procure 1.1 GW of clean dispatchable capacity via competitive tenders. It included:

[10] Full report: https://www.industry.gov.au/sites/default/files/October%202021/document/australias-long-term-emissions-reduction-plan.pdf

[11] https://consult.dcceew.gov.au/capacity-investment-scheme-public-consultation-paper

- Partnership with the NSW electricity infrastructure roadmap – providing Commonwealth support for up to 550 MW of firmed capacity (over and above the 380 MW already committed by NSW to date as part of the roadmap).
- South Australia/Victoria tender – Commonwealth support for up to 600 MW of dispatchable renewable capacity with 4-hr equivalent duration across two states.

Stage 1 attracted strong interest. As a result, in June 2023 Commonwealth government and state and territory ministers met, acknowledging the success of the pilot and agreeing to explore the possibilities for expansion of the scheme and the potential for it to replace the RET scheme that was due to end in 2030.

In August 2023, the government released a consultation paper outlining potential options for expansion of the CIS. This paper and responses to it by industry informed the significant expansion announced on 23 November 2023.

On 22 November 2023, the results for the NSW tender were announced resulting in six successful bids for major energy projects totalling 1,075 MW of reliable capacity. The successful bids were:

- One 4-hour storage battery (Akaysha Energy's Orana Renewable Energy Zone battery), located in Wellington in central west NSW, with 415 MW of capacity and 1,660 MWh in four-hour storage capacity.
- Two 2-hour storage batteries (AGL Liddell Battery 500 MW and 1,000 MWh, Iberdrola Smithfield battery 65 MW, 130 MWh).
- Three virtual power plants of 2-hour storage capacity (through Enel X demand response project 95 MW minimum duration 2 hours)

All successful projects are targeting commercial operations by December 2025.[12]

The South Australia/Victoria tender is currently open for bids. The tender is seeking bids for up to 600 MW of 4-hour equivalent (or 2,400 MWh) of dispatchable capacity. Projects must be in South Australia or Victoria and have a minimum storage duration of 2 hours and a minimum size of 30 MW. The tender intends to allocate:

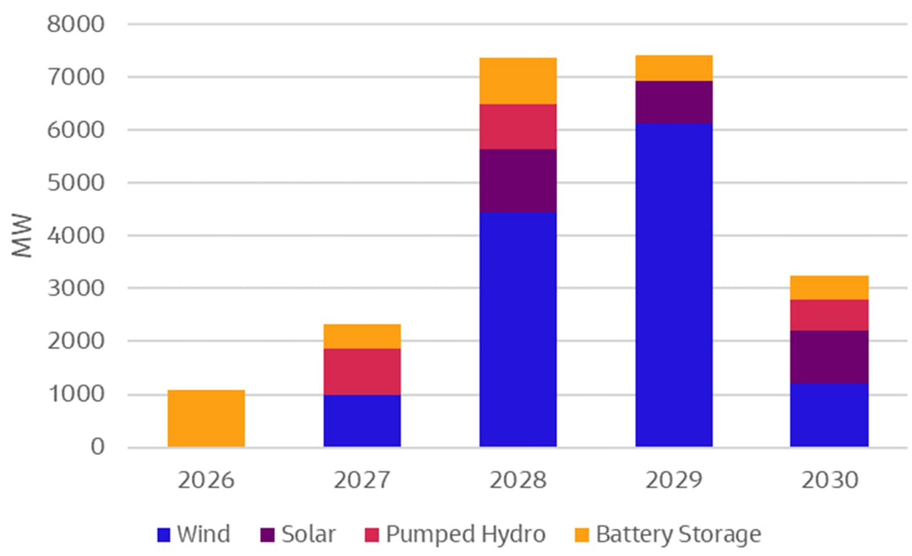
- 800 MWh to South Australia.
- 800 MWh to Victoria.
- An additional 800 MWh allocated to either South Australia or Victoria based on the assessed merit of projects.

AEMO Limited, together with its subsidiary AEMO Services Limited (ASL) is administering the competitive CIS tender on behalf of the Australian Government.

Under Jacobs' assumptions, most projects are assumed to be commissioned approximately two years after being awarded a capacity investment scheme agreement (CISA). Therefore, VRE capacity under the CIS is likely to commence operating from 2027, with the majority of the buildout operating from 2028 to 2029 (Figure A-2). Under the scheme, 3 GW of large-scale solar, and 12.8 GW of wind capacity is underwritten by 2030. Similarly, 2.3 GW of pumped hydro, and 3.3 GW of large-scale storage comes online under the CIS. These buildouts help meet the 23 GW national renewables target, and 9 GW national dispatchable capacity target.

[12] https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-capacity-investment-scheme-supports-nsw-deliver-1gw-cleaner-cheaper-more-reliable-energy-nsw

Figure A-2. CIS Capacity buildout, all scenarios

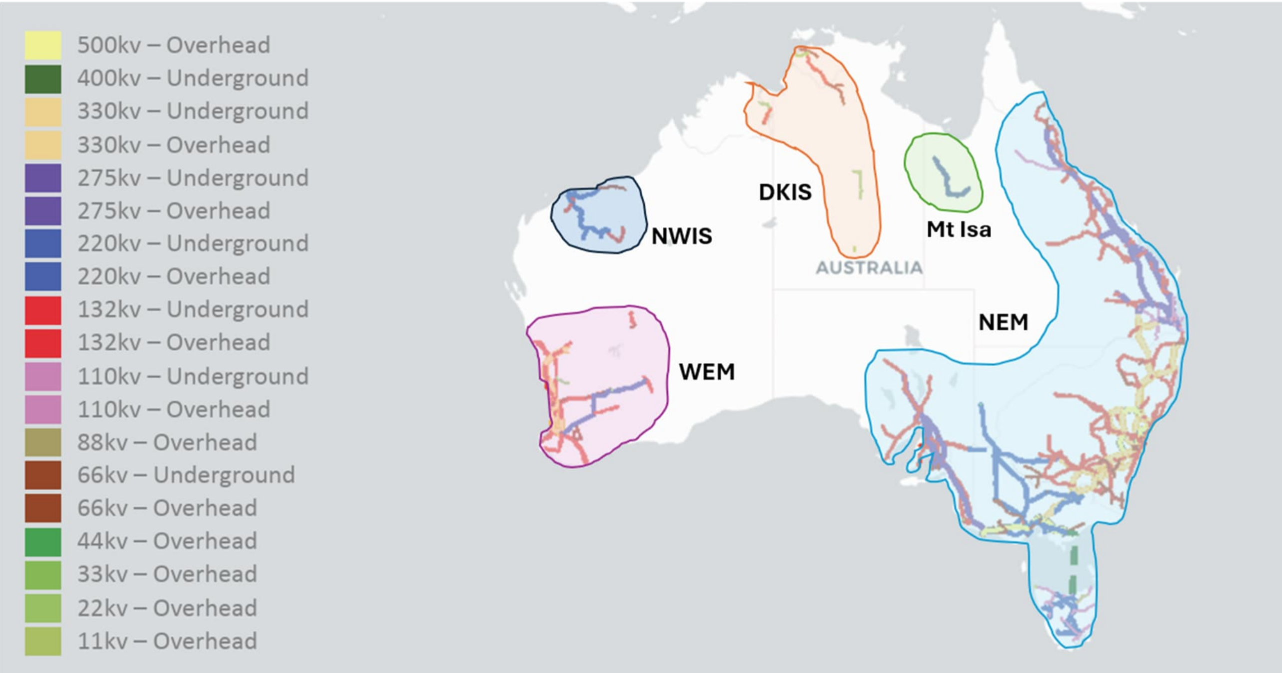


Appendix B. Market specific operation and assumptions

This assessment covers multiple markets across Australia, specifically:

- The National Electricity Market (NEM), covering Victoria, New South Wales, the Australian Capital Territory, Tasmania, southern South Australia, and most of central and south-east Queensland. The NEM is operated by the Australian Energy Market Operator (AEMO), a federal government entity.
- The Wholesale Electricity Market (WEM), covering south-west Western Australia, including Perth and surrounds. The WEM is also operated by AEMO, although under different rules.
- The North-West Interconnected System (NWIS), a non-unified grid made up of multiple interconnected networks within the Pilbara region in north-west Western Australia, including Port Hedland and surrounds. The overall operator of the system is Pilbara ISOCo, an independent system operator. Horizon power, Alinta Energy, and Rio Tinto all operate individual grids within the NWIS, amongst other smaller companies.
- The Darwin-Katherine Interconnected System (DKIS), covering the area between and surrounding Darwin and Katherine in the Northern Territory. The majority of electricity in the DKIS is generated from assets owned by Territory Generation, and the sole distributor is Power and Water Corporation, both state government-owned corporations.
- Mt Isa, which has an isolated grid including mostly mining activities as well as the town itself. It is served by the North West Power System operated by APA Group, a private company with significant gas assets in the area.

Figure B-1. Overview of the Australian electricity markets



Source: Australian Renewable Energy Agency

B.1 NEM

The assumptions specific to the NEM are summarised in Table B-1.

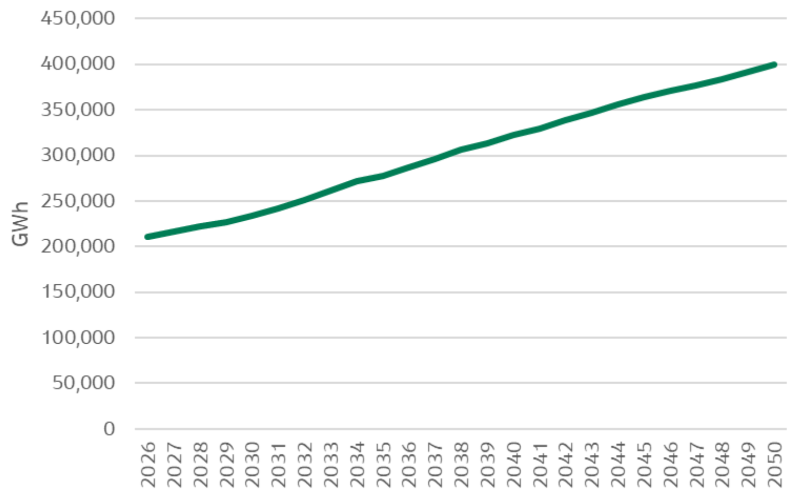
Table B-1. Key scenario assumptions

Assumption	Parameter	Reference case
Demand	Demand growth	AEMO ESOO 2024 Central (Step Change).
	EV growth	AEMO ESOO 2024 Central (Step Change).
	PV and storage	Jacobs assumption.
Fuel prices	Gas prices	Based on the ACCC LNG netback forward curve in the short term. Converges to AEMO 2024 GSOO Step Change by 2030.
	Coal prices	Based on the Draft 2025 IASR in the short term. Converges to AEMO 2024 ISP Central by 2030.

B.1.1 Demand in the NEM

In August 2024, AEMO released their 2024 Electricity Statement of Opportunities (ESOO). Of the scenarios modelled, the underlying energy demand forecast from the 2024 ESOO Step Change (Central) scenario is utilised in all scenarios. The current underlying demand forecast is displayed in Figure B-2.

Figure B-2. NEM underlying consumption forecasts



The above demand trajectory assumes that energy consumers are critical to decarbonisation, with strong uptake in rooftop PV, battery systems, and electric vehicles (EVs). Larger industries are assumed to play a role by electrifying their operations or switching to green hydrogen to support their industrial loads which are hard to electrify.

By 2040, 23% of underlying consumption is assumed to be met by distributed energy resources, behind-the-meter batteries will have a total storage capacity large enough to store up to 21% of household daily consumption, and 60% of all road transport is assumed to be an EV.

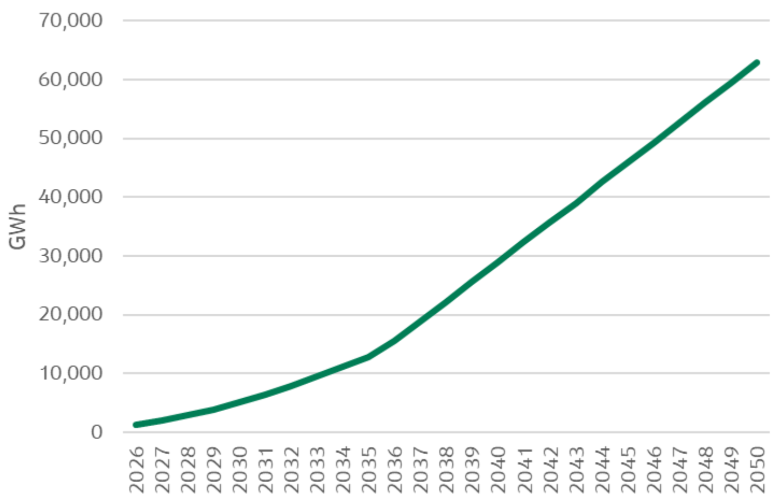
The energy and peak demand forecasts are applied to historical half-hourly demand profiles. This forecast provides a baseline impact of macroeconomic factors on demand over the forecast horizon. The hourly demand profiles used in the forward modelling are based on adjusted historical profiles from 2019 in which the rooftop PV component is added back to reflect underlying demand. This approach enables us to consider changing uptake of rooftop PV in our projections. Some embedded generation, such as small-scale cogeneration is not included in the model, and the native load forecasts are adjusted accordingly.

The use of the 50% PoE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch. The load is modelled hourly and therefore the peak is applied as an hourly load in the model rather than half-hourly as it occurs in the market.

B.1.1.1 Electric Vehicles (NEM)

The electric vehicle forecast for all scenarios is based on the AEMO 2024 ESOO, for the NEM only. After 2054, the forecast has been linearly extrapolated up to 2060. The current trajectory is displayed in Figure B-3.

Figure B-3. Electric vehicle charging consumption forecasts



Source: Jacobs' analysis of AEMO data

In the short term, limited policy incentives and current trends for EVs indicate a subdued outlook to the late 2020s. However, with EVs projected to be more cost-competitive and availability of charging infrastructure expected to increase, an acceleration point in EV uptake is forecast for 2031. In the long-term, consumption from EVs is higher across the NEM due to a combination of factors including the addition of articulated trucks which consume an order of magnitude more electricity than cars and increased ability of rentals to use and charge EVs.

Whilst EV purchases are the leading factor for the forecast of EV charging consumption, vehicle mix, changing driver behaviours, and charging patterns also play a role in future electricity consumption. The 2024 forecast assumes charging consumption has reduced at a greater rate than EV sales. EV sales now projected to be a greater mix of light and medium-sized vehicles which demand less electricity from the grid, relative to larger EVs.

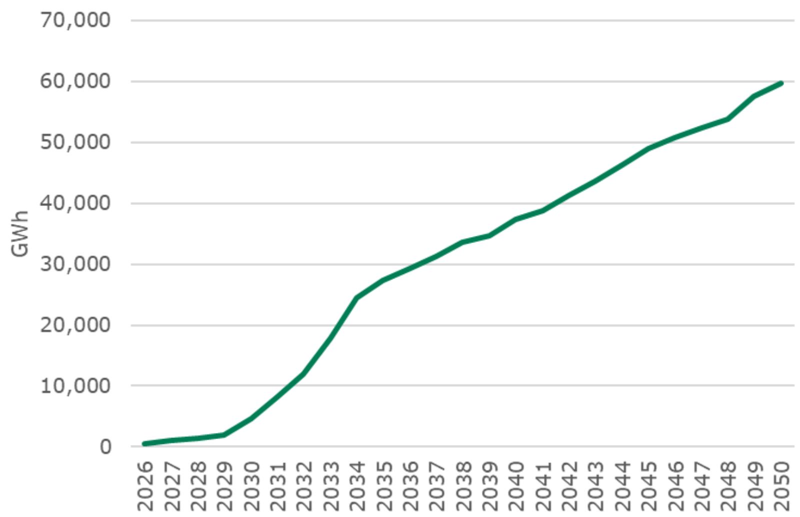
Over time, a greater number of drivers will switch from 'convenience charging' (i.e., charging in the evenings when returning from work, with a greater preference for convenience over electricity costs), to 'smart' charging where drivers make use of their potential daytime rooftop solar PV generation, or cheaper night-time TOU electricity rates. By 2040 it's assumed that 46% of drivers are still relying on convenience charging, down from approximately 75% of drivers today.

B.1.1.2 Green hydrogen production (NEM)

Green hydrogen will play an important role in Australia's energy transition, by enabling industrial users to decarbonise their hard-to-electrify operations, and by providing a clean and dispatchable form of generation to supplement variable renewable energy. Production of green hydrogen involves electrolysis which consumes electricity, either from the grid or from on-site generation. AEMO's 2024 Central scenario forecast associated with the production of green hydrogen is shown in Figure B-4.

Electricity consumption from hydrogen production is made up from hydrogen produced for domestic use, and hydrogen produced for exporting to other countries. In the short term, the forecast for domestic hydrogen production is built upon CSIRO's HyResource[13] database which tracks all current, proposed, and likely hydrogen projects around Australia and their proposed capacities and timelines. Electricity consumption for domestic hydrogen production has commenced with a small number of projects now in operation. In all scenarios, this is forecast to slowly increase over the next ten years. By 2035, the forecast is constrained by the gas distribution lines reaching 10% hydrogen by volume, which is the technical limit of hydrogen allowed in the current pipelines without physical modifications or causing damage to gas appliances. All future growth after 2030 is assumed to be from hydrogen facilities which are directly connected to industry hubs using hydrogen-compatible pipelines. Only 50% of domestic hydrogen production is assumed to be powered by grid generation.

Figure B-4. Electricity consumption from hydrogen production



A small portion of electricity consumption from hydrogen production is attributed to hydrogen produced for export. In Queensland, South Australia, and Tasmania, an industry for hydrogen exports is assumed to commence from 2033. This is aligned with each region's current plans for construction of new hydrogen export facilities. New South Wales and Victoria are assumed to have a smaller hydrogen export industry from Rooftop PV.

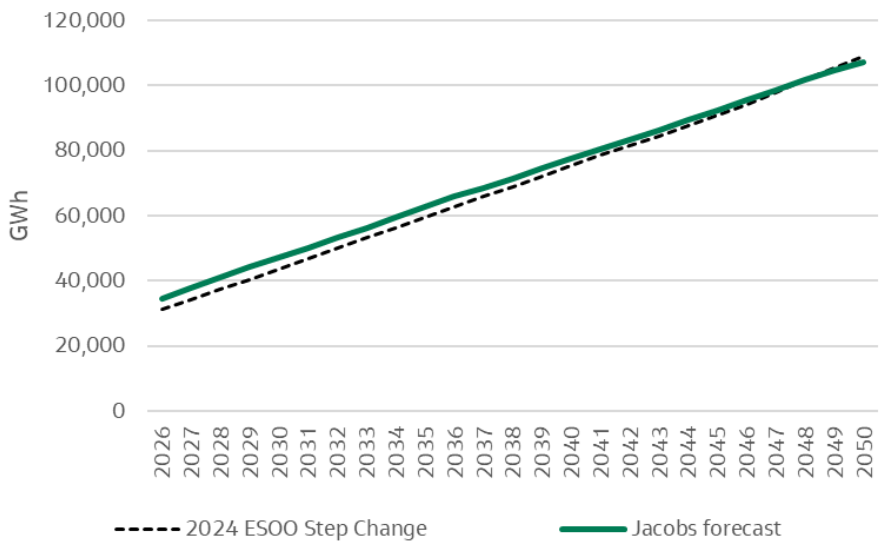
B.1.1.3 Rooftop PV

Rooftop PV systems (less than 100 kW) in the NEM have continued its rapid uptake. The pipeline for photovoltaic non-scheduled generation (PVNSG), which represents grid-connected PV and commercial developments between 100 kW and 5 MW that are not scheduled for dispatch, has also increased. These installations face fewer barriers in obtaining grid connection and when co-located with demand, avoid power losses and costs associated with acquiring this power through the grid.

Figure B-5 displays the forecast for all scenarios (for the NEM), and the 2024 ESOO Step Change forecast for rooftop PV and PVNSG generation. Jacobs' NEM forecast is rebased from 2024 actual numbers provided by the Clean Energy Regulator.

Figure B-5. Rooftop PV and PVNSG forecasts

[13] CSIRO, HyResource, at https://research.csiro.au/hyresource/



Source: Jacobs' analysis of AEMO data

Owner occupied households are a leading adopter of rooftop PV with a current NEM-wide penetration of 35%. By 2050 this is forecast to increase to over 70%.

Policy support to increase uptake of rooftop PV has moderated in recent times and the impact of high levels of distributed generation has led to new reforms to manage the energy flows from these systems. Included in these reforms is the potential for negative prices to flow through to exporters in the form of negative feed-in tariffs, which would de-incentivise export. There are also reforms being considered on active management of DER such as remote disconnection capabilities.

B.1.1.4 Electrification

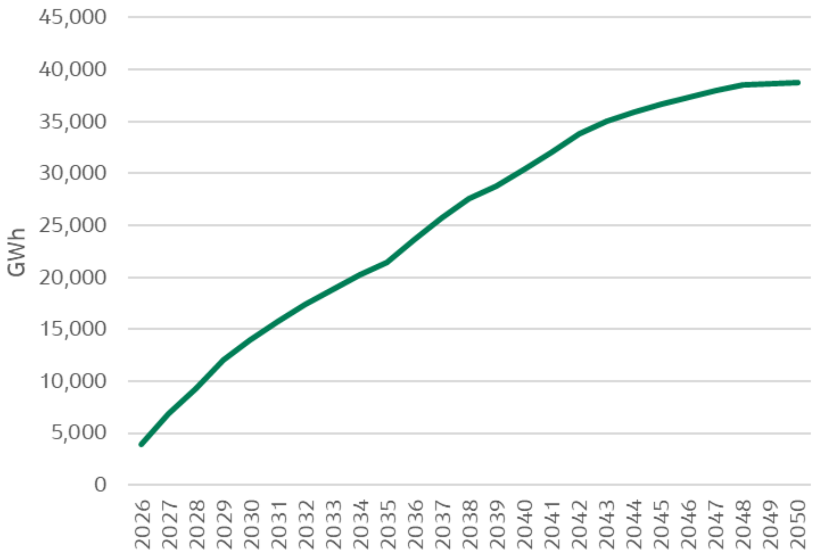
Certain industries, operations, or appliances use fuel sources which are non-renewable and emit carbon. This may include internal combustion engine vehicles, gas stoves, or gas water heating. Electrifying by switching to an alternative technology powered by electricity can allow these practices to decarbonise in the long-term. Although, electricity from the grid is still dominated by carbon emitting thermal generation today, electric technologies can be powered by behind-the-meter renewable generation, or by a future electricity grid which will be mostly supplied by clean energy. Future electricity consumption attributed to the projected rate of electrification is shown in Figure B-6. Jacobs' electrification forecast for the NEM in all scenarios is equivalent to AEMO's 2024 ESOO Step Change scenario.

The rate of future electrification will be driven by cost-efficiencies including appliance replacement costs, and electricity infrastructure capabilities and costs. Electrification in residential and commercial buildings will largely comprise space heating, water heating, and cooking appliances.

Electrification of the transport sector is excluded from this forecast and is in a separate forecast shown in Figure B-6.

Electrification in the industrial sector will comprise most industrial oil and gas demand, however some high-heat processes such as the direct reduction process for iron and steel are difficult to electrify and will require further technological advancements.

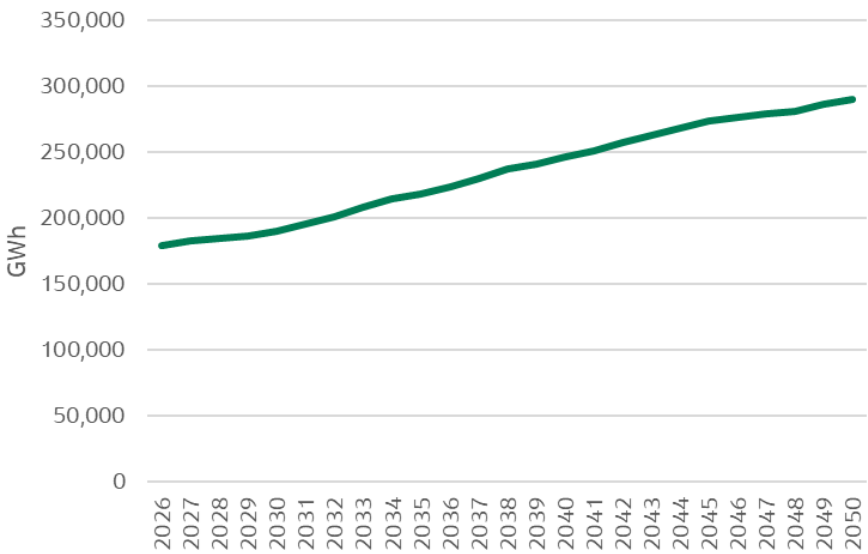
Figure B-6. Consumption from electrification forecasts



B.1.1.5 Operational demand

Operational demand refers to electricity demand met by the grid, and excludes demand met by distributed PV and storage. Greater behind-the-meter generation means that less operational demand needs to be met by central forms of generation in the grid. The impacts of changes to underlying demand, electric vehicles, hydrogen production, electrification, and distributed generation are reflected in the changed operational demand as shown in Figure B-7.

Figure B-7. Operational demand forecasts



B.1.2 State energy policies

State energy policies are not incorporated in any scenario. This modelling investigates carbon pricing on a national level and aims to assess these policies only against national and global climate change metrics.

B.1.3 Participant behaviour

B.1.3.1 Market structure

We assume the current market structure continues under the following arrangements:

- Victorian and New South Wales generators are not further aggregated.
- The generators' ownership structure in Queensland remains as public ownership.
- The South Australian assets continue under the current portfolio groupings.

In addition, the following assumptions have been made about incumbent generators based on announcements to the market:

- AGL announced the retirement of its Liddell power station, located in New South Wales, in 2022/23.
- Origin announced the delay of the retirement of Eraring Power Station from 2025 to 2027 after an agreement with the NSW government.
- EnergyAustralia announced the retirement of Yallourn Power Station by mid-2028.

Over the last five years, at least ten power stations in the NEM have either permanently retired or have mothballed capacity. Eight of the ten were coal-fired power stations, in each NEM region except Tasmania. The other two, Pelican Point and Swanbank E, are combined cycle gas turbines – these have now been brought back to service. The total coal-fired capacity retired over this time amounts to just under 5,200 MW.

The two key reasons explaining these retirements are ageing plant and an oversupply of capacity in the NEM, due to the LRET and the reduction in grid demand that took place between 2009 and 2015. The LRET trajectory was designed for renewable energy plant to fill in the supply gap caused by growing demand, but it came at a time when electricity demand had a long period of contraction. These factors combined with the introduction of the carbon price on 1 July 2012 also led to the retirement of smaller, older, less efficient coal-fired power stations such as Collinsville, Playford B, Energy Brix, and Munmorah.

With increasing renewable energy generation, some brown coal capacity will become seasonally baseload, but with shutdowns during off-peak months depending on the prevailing level of plant maintenance. Some strategic bidding of brown coal capacity to support market prices will emerge.

B.1.3.2 Contract position

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed[14] for operational reasons or bid at its marginal cost, to ensure that the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out. This strategy maximises profit in the short-term, excluding any long-term flow on effects into the contract market.

It is assumed that half to three-quarters of the capacity of baseload and intermediate plants bid at marginal cost to represent the contracted level.

[14] "Self-committed" means that the generator specifies the timing and level of dispatch with a zero-bid price. If generators wish to limit off-loading below the self-commitment level, a negative bid price down to -$1,000/MWh may be offered. This may result in a negative pool price for generators and customers.

B.1.4 Hydro modelling

Hydro plants are set up with fixed monthly generation volumes. Strategist dispatches the available energy to take the top off the load curve within the available capacity and energy. Any run-of-river component is treated as a baseload subtraction from the load profile.

Based on our market information, we have produced monthly and annual energy values for the Snowy Hydro units. Daily release constraints cannot be modelled in Strategist. The monthly minimum generation for Blowering and Guthega is based on market information, largely driven by the irrigation requirements of these hydro-electric systems. Table B-2 shows the monthly generation for the various hydro-electric plants. Hydro Tasmania's generation is set to the stated long-term average of 8,700 GWh.

Table B-2. Monthly energy for small hydro-electric generators (GWh)

	Small Hydro			Victorian hydro			Snowy Hydro			Hydro Tasmania
Month	Barron	Hume (Vic)	Kareeya	Dartmouth	Eildon 1-2	Kiewa/ McKay	Murray	Upper Tumut	Lower Tumut	
January	15.93	7.62	26.83	26.78	42.37	8.27	114.74	134.21	46.20	716.53
February	30.92	8.60	13.45	23.56	33.25	7.23	178.19	192.44	43.67	508.08
March	20.80	9.27	21.48	21.42	31.32	7.23	172.03	148.78	43.84	677.22
April	18.74	8.41	20.59	10.71	27.54	12.40	149.48	121.72	45.78	708.18
May	11.80	6.04	36.35	5.36	1.57	24.80	166.52	164.12	51.16	783.00
June	15.93	0.00	47.36	5.36	0.00	33.07	195.22	196.68	39.57	957.00
July	11.80	0.00	26.24	8.57	1.13	36.17	238.83	261.92	44.58	783.01
August	17.05	0.00	32.78	10.71	4.22	43.40	207.94	153.79	47.54	696.00
September	13.49	6.04	28.91	10.71	13.17	47.54	42.00	8.84	47.69	870.00
October	19.11	10.84	28.62	12.85	14.14	51.67	125.00	10.00	43.60	835.53
November	4.87	9.91	28.32	21.42	14.30	44.44	91.60	115.64	46.88	568.80
December	6.93	8.54	26.54	23.56	22.56	28.94	114.39	121.64	44.50	596.67
Total	187.38	75.26	337.46	181.00	205.57	345.16	1795.93	1629.79	545.00	8,700

B.1.5 New generation entry

After selecting new entry to meet AEMO's minimum reserve criteria, Jacobs' pool market solution indicates whether prices would support additional new entry under typical market conditions, and these are included in the market expansion if required. We assume that:

- Some 75% of baseload plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position.
- New entrants will require that their first-year cash costs are met from the pool revenue before they will invest.
- The next new thermal entrants in Victoria will be either peaking plant to meet reserve requirements or new combined cycle plant when such plant can achieve at least 50% capacity factor.
- Infrequently used peaking resources are bid near market price cap or removed from the simulation to represent strategic bidding of such resources.

Cost and financing assumptions used to develop the long-term new entry prices are provided in Table B-3, applicable to the financial year 2023/24 in June 2023 dollars. The real pre-tax equity return applied was 9.0%

per annum and the change in CPI applied to the nominal interest rate of 8.6% per annum was 2.5% per annum. Thermal capital costs are generally assumed to remain flat over the modelling horizon.

Newer renewable technologies have higher initial costs and greater rates of real cost decline, and if combined with a CCGT for firming purposes, together provide the least cost approach to delivering firm round the clock power over most of the projection period. This is the case for solar and wind, but the higher capacity factor available to wind means that the combination of wind and gas is cheaper than the combination of solar and gas. The combination of all three sources may be cheaper again while any curtailment of renewable supply due to low demand is able to be diverted to storage on the grid or to supply new forms of demand such as electric vehicles. New entry prices are based on hybrid options such as wind supported by gas generation as well as solar supported by gas generation. Over the longer term this means that gas prices have a reduced impact over long-term prices because renewable generation can replace supply in periods where renewable resources are plentiful. Table B-3 displays the financial assumptions for a CCGT and wind plant in 2024 and illustrates how the combination of both technologies for providing baseload/flat demand is cheaper than using a CCGT alone.

Table B-3. Thermal new entry cost and financial assumptions (FY 2024)

	CCGT assumptions							Wind assumptions		Wind + CCGT
State	Capital cost $/kW	Fuel cost $/GJ	WACC (% real)	Interest rate (% nominal)	Debt level	LRMC at 92% capacity factor $/MWh	LRMC at lower capacity factor (with wind) $/MWh	Wind capacity factor	Wind cost $/MWh	LRMC combined wind/CCGT
SA	$1,862	$16.03	7.4%	8.6%	60%	$148.23	$165.23	39%	$85.73	$128.10
Victoria	$1,824	$15.36	7.4%	8.6%	60%	$127.45	$142.29	38%	$85.50	$115.94
NSW	$1,903	$15.35	7.4%	8.6%	60%	$129.44	$144.34	38%	$86.36	$117.46
QLD	$1,886	$15.87	7.4%	8.6%	60%	$134.69	$146.22	32%	$75.32	$118.48

Note: fuel cost shown as indicative only.

B.1.6 Generator costs

This section describes the costs associated with thermal plant, including coal and gas prices, and renewable generation and storage technologies.

B.1.7 Long-term thermal plant costs

The marginal costs of thermal generators consist of the variable costs of fuel supply, including fuel transport, plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table B-4 We also include the net present value of changes in future capital expenditure, which would be driven by fuel consumption for open cut mines that are owned by the generator such as brown coal in Victoria.

Thermal power plants are modelled with planned and forced outages, with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 55% and 93% and gas fired plants have available capacity factors between 87% and 95%.

For more detail on the thermal plant properties including variable costs, refer to Table B-4.

Table B-4. Indicative average variable costs for existing thermal plant

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$8 - $14	Black Coal – New South Wales	$23 - $40
Gas – Victoria	$125 - $230	Black Coal - Qld	$17 - $31
Gas – South Australia	$105 - $147	Gas – Queensland	$97 - $114
Oil – South Australia	$222 - $352	Oil – Queensland	$264 - $295
Gas Peak – South Australia	$259 - $370		

Source: Jacobs' analysis

B.1.8 Gas prices

Gas prices are typically forecast based on the projected demand-supply balance for energy in Eastern Australia considering the essential features of Australian wholesale gas markets. These features are:

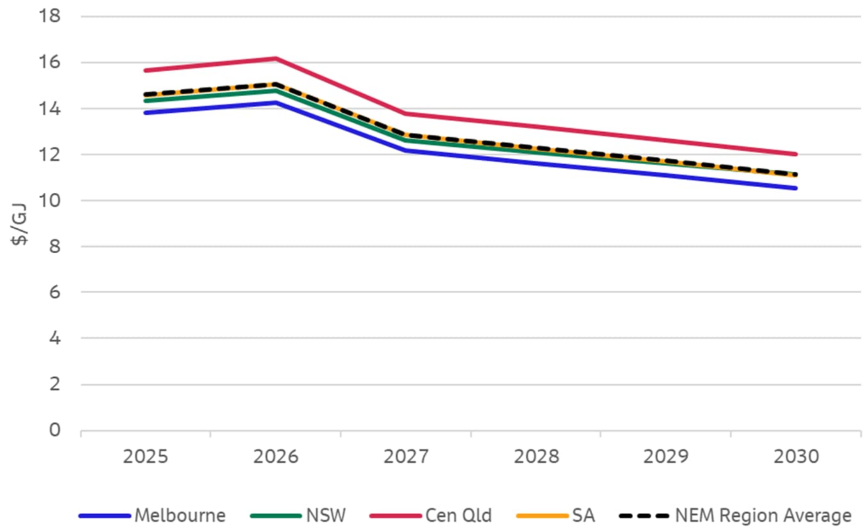
- A limited number of gas producers.
- Limited supply side additions due to moratoria and ESG pressures.
- Dominance of long-term contracting and limited short-term trading.
- A developing network of regulated and competitive transmission pipelines.
- Domestic market growth driven by gas-fired generation and large industrial projects.

Informing the gas price forecast for the NEM in all scenarios in Figure B-8 is the gas market analysis from the Chief Economist's Resources & Energy Quarterly March 2024, and the ACCC LNG netback forward curve.

The average gas prices in the short term are projected to stay high, as supply is expected to remain tight during the mid-2020s from Europe's increased LNG consumption replacing Russian pipeline gas. Towards the end of the decade, prices are forecast to ease as gas supply improves from new US and Qatari liquefaction facilities. However, this period will remain volatile with prices elevated above historical averages, as Europe's high seasonal gas demand will be largely dependent on US LNG imports and China's ability to resell their contracted US imports to Europe.

These high prices are also underpinned by elevated oil prices, and the price uncertainty from the sanctions imposed on Russian crude oil. Over 80% of Australian LNG exports are sold under long-term contracts with prices linked to the Japanese Customs Crude oil price, which in turn is reflective of the Brent oil price.

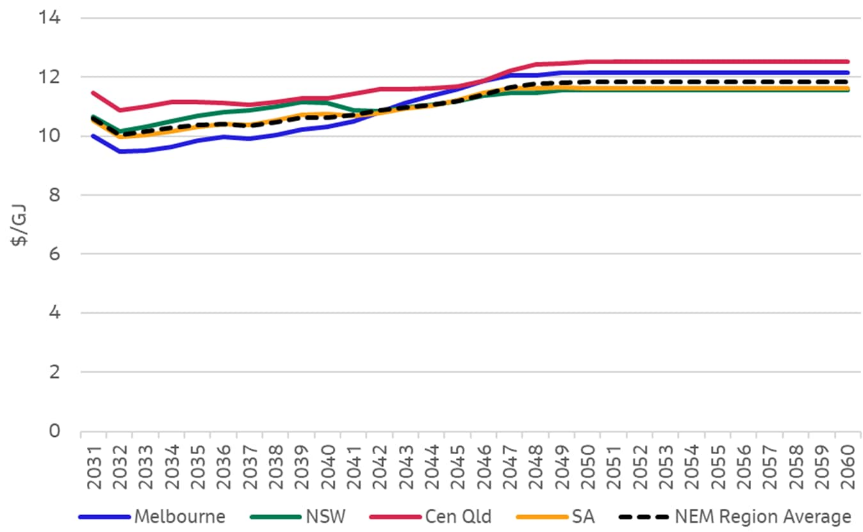
Figure B-8. Short term gas price forecast, all scenarios, eastern states



Source: Jacobs' analysis. $Dec 2023 dollars

As shown in Figure B-9, Jacobs assume gas prices remain elevated in the short term, returning to historical levels by 2030. Assumptions for the long-term trajectory of gas prices are outlined in Table B-5.

Figure B-9. Long-term gas price forecast, all scenarios, eastern states



Source: Jacobs' analysis.

Table B-5. Long-term gas market model assumptions

Parameters	Base Scenario
Gas Demand	AEMO 2024 GSOO Step Change Scenario. Reflects an energy system based around central estimates of all key drivers. This scenario reflects a moderate rate of change in Australia's energy sector
Gas Supply	ACCC Reserves and resources Gippsland Basin - remains at 200 PJ/year for much of the period before declining. Otway and Bass Basins - terminal decline from 2028

Parameters	Base Scenario
	Cooper Basin - very limited to 2022, then grows back to over 100 PJ/year due to development of unconventional resource Surat/Bowen CSG - growing supply with development of resources additional to LNG requirements. Accounts for 50% of supply by 2030s. New South Wales CSG - no supply NT Gas - enters the market and grows slowly, constrained by high transmission costs to most markets
LNG Import Terminals	Port Kembla Energy Terminal (PKET) Jemena proposes enhancing the EGP to enable bi-directional gas flow. Once completed the upgraded system will have an initial capacity of 200 TJ/d for reverse flows to Victoria, with potential for expansion to 325 TJ/d. Venice's Outer Harbour LNG Import Terminal SEA Gas and Venice Energy have confirmed the feasibility of reconfiguring the PCA to support bidirectional gas flows from South Australia to Victoria VIVA VIVA and/or Vopak projects could increase the capacity of the SWP, allowing for greater simultaneous gas injections from an LNG import terminal in Geelong and production facilities in Port Campbell.

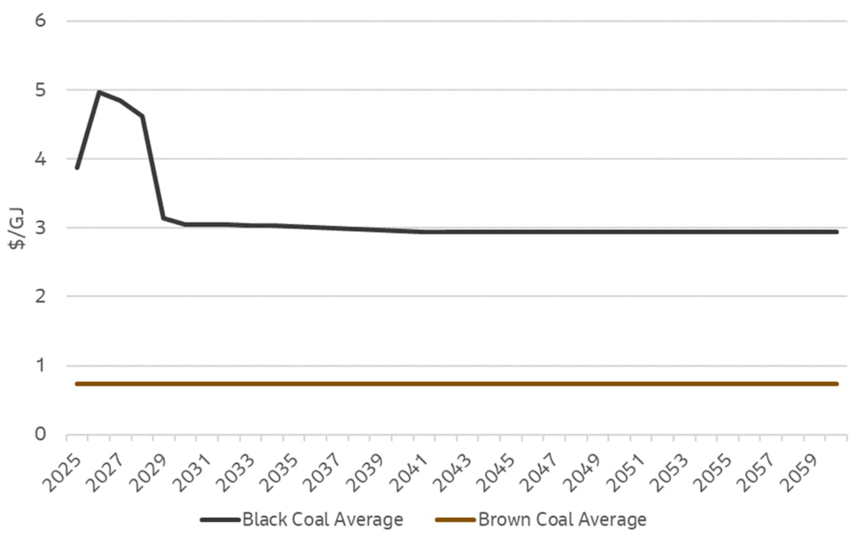
B.1.9 Coal prices

Black and brown coal prices for all scenarios are based on the AEMO Draft ISP 2025 (Central) in the short term and converge to AEMO ISP 2024 (Central) by 2030.

Because of the conflict in Ukraine, spot prices for black coal plants exposed to international prices have been significantly higher than previous years, forcing coal and gas generators in the NEM to bid at much higher levels. To ensure these effects are accurately reflected in our model, the prices of black coal have been increased in the short-term.

The average black and brown coal forecasts are illustrated in Figure B-10.

Figure B-10. Coal Prices, Jacobs Base scenario ($Dec 2024 dollars)



Source: Jacobs' analysis

B.1.10 Renewable energy and energy storage costs

This section summarises the cost projections for new entrant renewable energy generation (including onshore wind, large-scale solar PV, and bioenergy) and energy storage (batteries and pumped hydro) technologies. Figure B-11 presents levelised costs for new entrant wind and solar generation for the four largest NEM regions. Levelised cost of energy is a measure of the average cost of a generating asset spread over its lifetime calculated by dividing the net present value of the total costs over its lifetime by the generated electricity over its lifetime.

Figure B-12 displays a comparison for overnight capital cost projections to 2055 for all new entrant renewable generation and energy storage technologies modelled. Overnight cost of capital is calculated by dividing the cost of building a generating asset overnight by the maximum power it can deliver instantaneously.

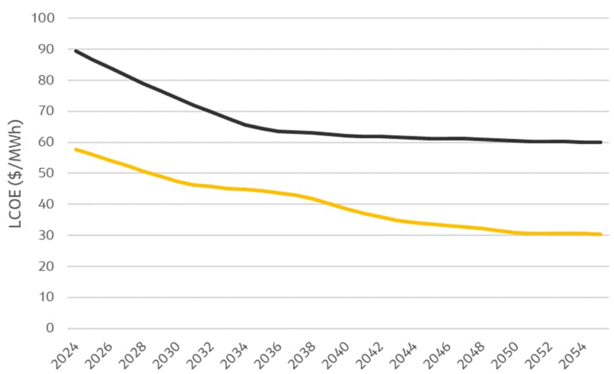
Jacobs' technology cost projections have been adapted from a combination of the following sources:

- **CSIRO's GenCost 2024 project dataset**[15] - the GenCost project is a collaboration between CSIRO and AEMO, together with stakeholder input, to deliver an annual process of updating electricity generation and storage costs. Each report incorporates updated current and future cost estimates and global electricity scenarios.
- **ASX announcements and financial year reports** – publicly-traded companies release information on the costs of capital and project costs when announcing the funding of their projects. This is publicly accessible on the ASX website. Jacobs maintains its own internal databases tracking the most recent announcements especially for solar and wind projects.

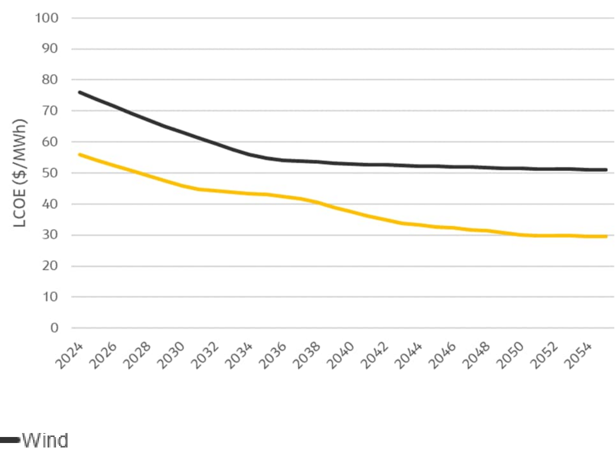
Figures for solar PV, onshore wind, battery storage, pumped hydro energy storage, offshore wind and high temperature solar thermal are based on the GenCost 2024 'Global NZE post 2050' scenario.

Figure B-11. Levelised cost of electricity for new entrant wind and solar PV generators, best sites

New South Wales



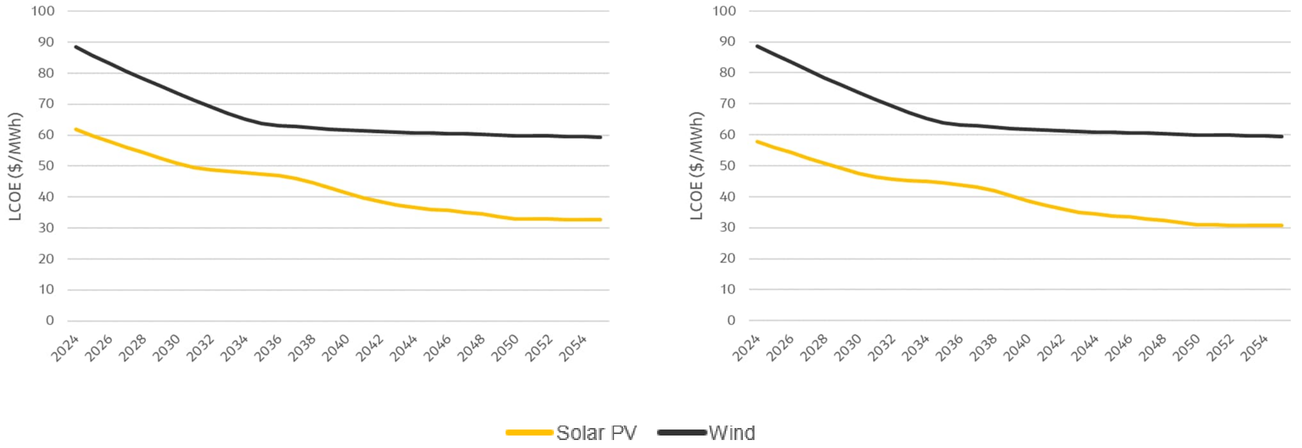
Queensland



Victoria

South Australia

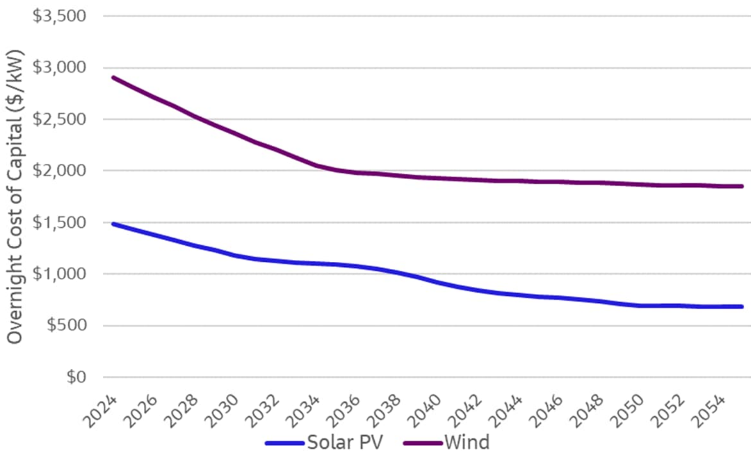
[15] The GenCost 2023 dataset can be accessed here: https://data.csiro.au/collection/csiro%3A44228v10



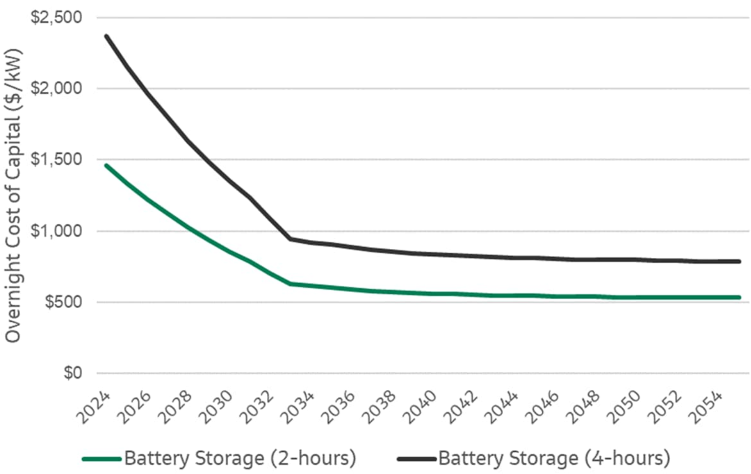
Source: Jacobs' analysis of CSIRO data. ***Note:*** *Costs are for best sites across the renewable energy zones in a region. Costs include capital costs, operating costs, construction finance, land and installation costs and local connection costs.*

Figure B-12. Overnight cost of capital by technology

Wind & Solar PV



Battery Energy Storage Systems (BESS)



Notes: Costs presented are averages and incorporate regional variation by regions within States.
Source: Jacobs' analysis of CSIRO data.

B.1.11 Interconnection and losses

B.1.11.1 Upgrades

On 15 December 2023, AEMO released their draft version of the 2024 ISP, detailing transmission upgrades categorised on timelines. Committed and actionable projects have been included in the modelling with the timing from the ISP (see Table B-6). Remaining transmission upgrades and their timings are included based on when they become economic (as determined in the modelling). These are labelled 'Future Upgrades' and include the QNI Medium and large interconnector upgrades that would facilitate these zones.

However, rising costs of materials and equipment, labour shortages and supply chain issues, and approval delays are increasing the likelihood of delays to several of these transmission projects. In all scenarios, Project EnergyConnect has been pushed back from 2024 to July 2026. Similarly, VNI West and Humelink have been moved back one year from 2028 to 2029, and Stage 1 of Marinus Link has been moved back from 2029 to 2030.

The presence of transmission upgrades in the modelling is important as these upgrades enable increased levels of generation capacity to enter other markets in the NEM.

Table B-6. Interconnector upgrades

From	To	Name in AEMO draft ISP 2024	Capacity	Indicative Timing (FY)
Committed Interconnector Upgrades				
NSW	Queensland	QNI Minor	460 MW	2023
Queensland	NSW	QNI Minor	190 MW	2023
Actionable Interconnector Upgrades				
Victoria	NSW	VNI Minor	170 MW	2023
South Australia	NSW	EnergyConnect	800 MW	2028
NSW	South Australia	EnergyConnect	800 MW	2028
-	-	HumeLink	2000 MW	2029*
Victoria	NSW	VNI West	1800MW	2029*
NSW	Victoria	VNI West	1800MW	2029*
Tasmania	Victoria	Marinus Link Stage 1	700 MW	2030
Future Interconnector Upgrades				
Queensland	NSW	QNI Medium	1260 MW	2032*
Tasmania	Victoria	Marinus Link Stage 2	700 MW	2035*

*Timing based on economic feasibility as assessed by Jacobs. Source: Jacobs' analysis of AEMO draft ISP 2024 interconnector upgrades

B.1.11.2 Interconnector limits

Assumptions on interconnect limits are shown in Table B-7. We have retained a Snowy zone in our Strategist model to better represent the impact of intra-regional constraints on each side of the Victoria/New South Wales border.

These limits are based on the maximum recorded inter-regional capabilities. The Victorian export limit to Snowy/New South Wales is sometimes up to 1,300 MW. The actual limit in a period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from New South Wales to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern New South Wales, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong.

Basslink has a continuous capacity of 478 MW and a short-term rating up to 600 MW. Basslink has been modelled with an optimised export limit that best uses the available thermal capacity of the cable to maximise the value of export trade. The optimisation was performed using a Strategist simulation to assess Victorian price versus export. The import limit was represented as a function of Tasmanian load according to the equation published by AEMO. This allows 323 MW of import at 800 MW and 427 MW at 1,100 MW of load.

Table B-7. Interconnection limits – based on maximum recorded flows

From	To	Capacity	Summer
Victoria	Tasmania	478 MW	
Tasmania	Victoria	600 MW	
Victoria	South Australia	650 MW	
South Australia	Victoria	650 MW	
South Australia	Red Cliffs	135 MW	
Red Cliffs	South Australia	220 MW	
Victoria	Snowy	1,300 MW	
Snowy	Victoria	1,900 MW	
Snowy	NSW	3,559 MW	3,117 MW
NSW	Snowy	1,150 MW	
NSW	South Queensland	120 MW	
South Queensland	NSW	180 MW	120 MW
NSW	Tarong	589 MW	
Tarong	NSW	1,078 MW	

B.1.11.3 Losses

Inter-regional loss equations are modelled by directly entering the loss factor equations published by AEMO except that we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO Report ‘Regions and Marginal Loss Factors: FY 2023-24’.

Negative losses are avoided by shifting the quadratic loss equation so that the minimum passes through zero. Intra-regional losses are applied as detailed in the AEMO Report.

B.2 WEM

The assumptions for the Reference Case are summarised in Table B-8.

Table B-8. Key scenario assumptions for WEM

Assumption	Parameter	Reference case
Demand	Demand growth	AEMO WEM ESOO 2024 Expected (Step Change).
	EV growth	AEMO WEM ESOO 2024 Expected (Step Change).
	PV and storage	AEMO WEM ESOO 2024 Expected (Step Change).
Fuel prices	Gas prices	Jacobs Assumption – based on historical prices from WEM generators
	Coal prices	Jacobs Assumption – based on historical prices from WEM generators

B.3 NWIS

The assumptions for the Reference Case are summarised in Table B-9.

Table B-9. Key scenario assumptions for NWIS

Assumption	Parameter	Reference case
Demand	Demand growth	National Greenhouse and Emissions Reporting scheme, 2023-2024 designated generating facility data.
Fuel prices	Gas prices	Jacobs assumption – based on historical prices in the NWIS.

B.4 DKIS

The assumptions for the Reference Case are summarised in Table B-10.

Table B-10. Key scenario assumptions for DKIS

Assumption	Parameter	Reference case
Demand	Demand growth	2023 Northern Territory Electricity Outlook Report Data.
	PV and storage	2023 Northern Territory Electricity Outlook Report Data.
Fuel prices	Gas prices	Jacobs assumption – based on historical prices.

B.5 Mt Isa

The assumptions for the Reference Case are summarised in Table B-11.

Table B-11. Key scenario assumptions for Mt Isa

Assumption	Parameter	Reference case
Demand	Demand growth	National Greenhouse and Emissions Reporting scheme, 2023-2024 designated generating facility data.
Fuel prices	Gas prices	Jacobs assumption – based off a modification of SE QLD's gas prices.

Appendix C. Capacity and generation mix comparison

Figure C-1. Capacity mix comparison, extended Safeguard Mechanism in 1.5 degree warming compared to reference scenario

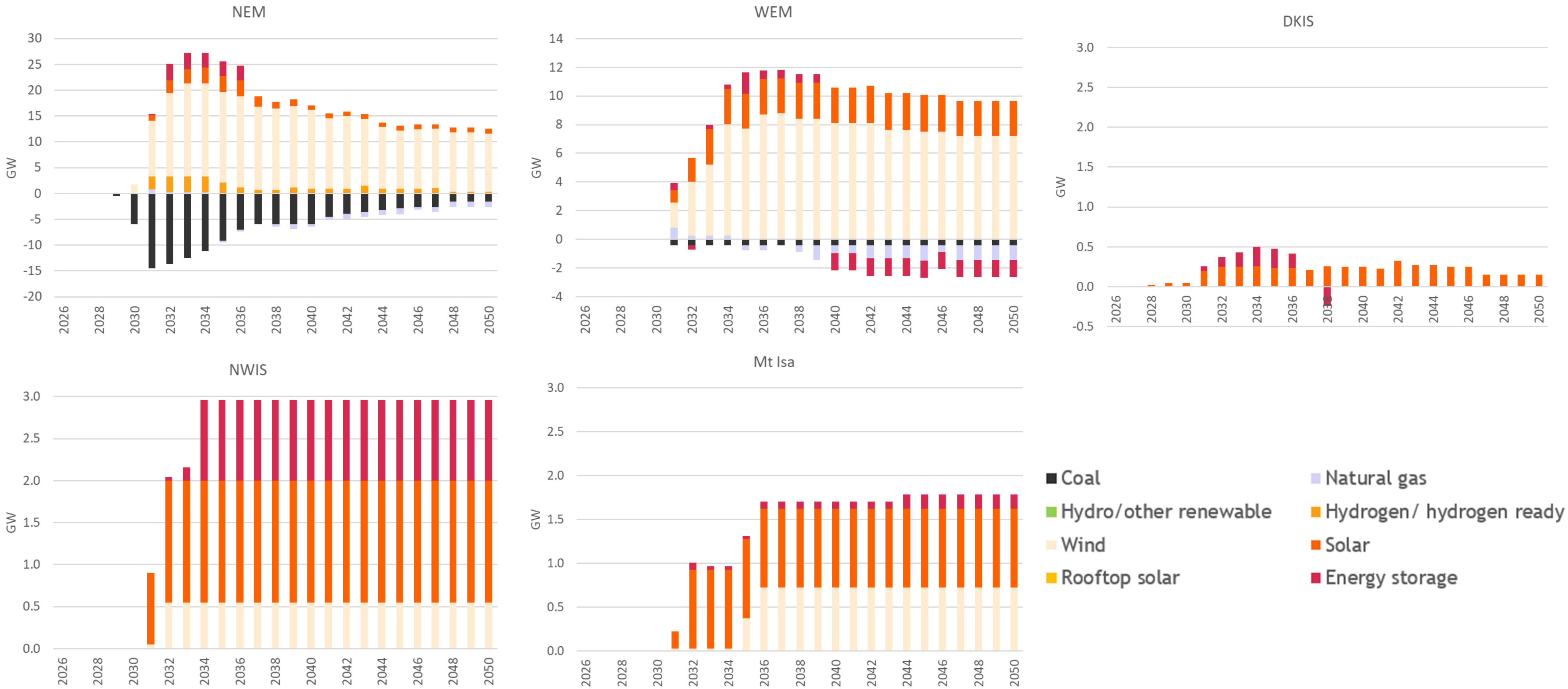


Figure C-2. Generation mix comparison, extended Safeguard Mechanism in 1.5 degree warming compared to reference scenario

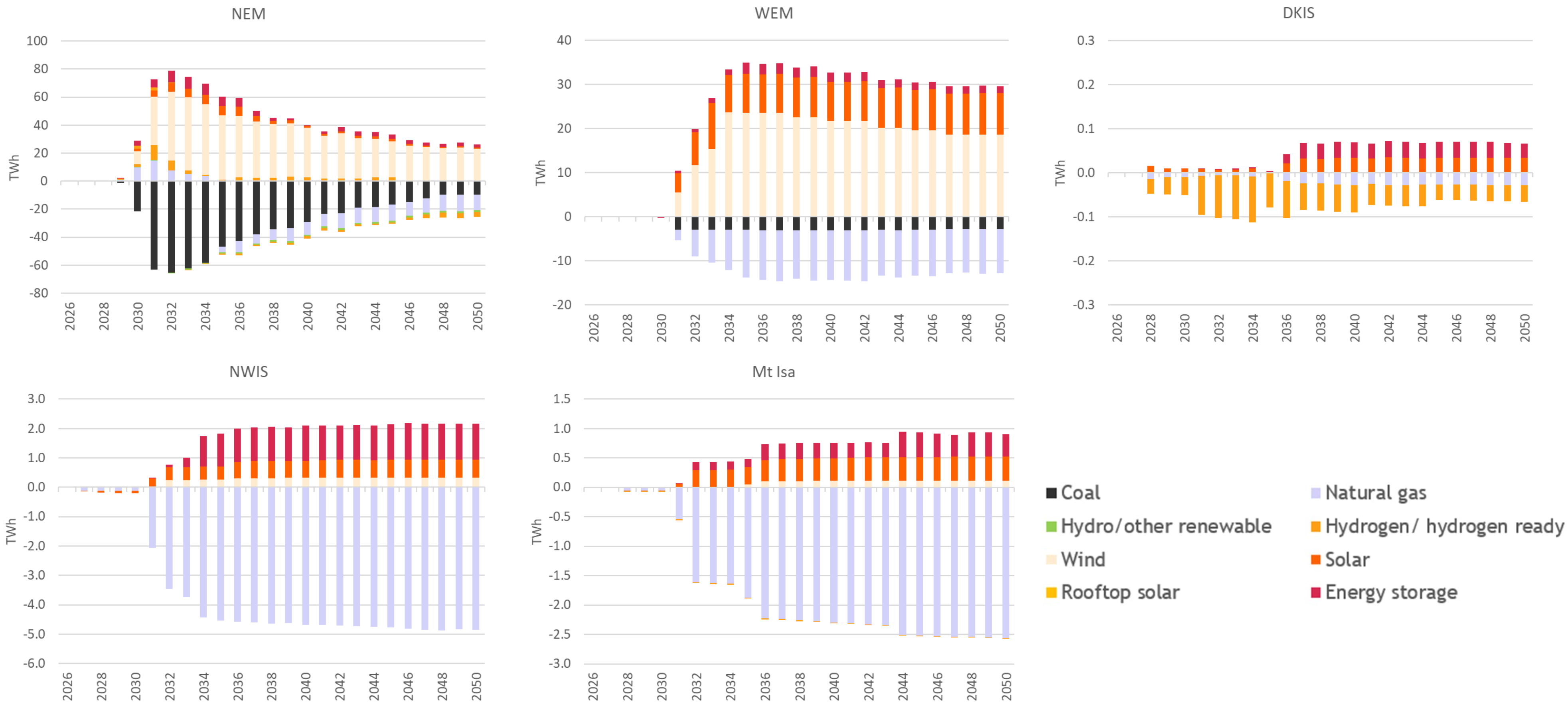


Figure C-3. Capacity mix comparison, extended Safeguard Mechanism in 2 degree warming compared to reference scenario

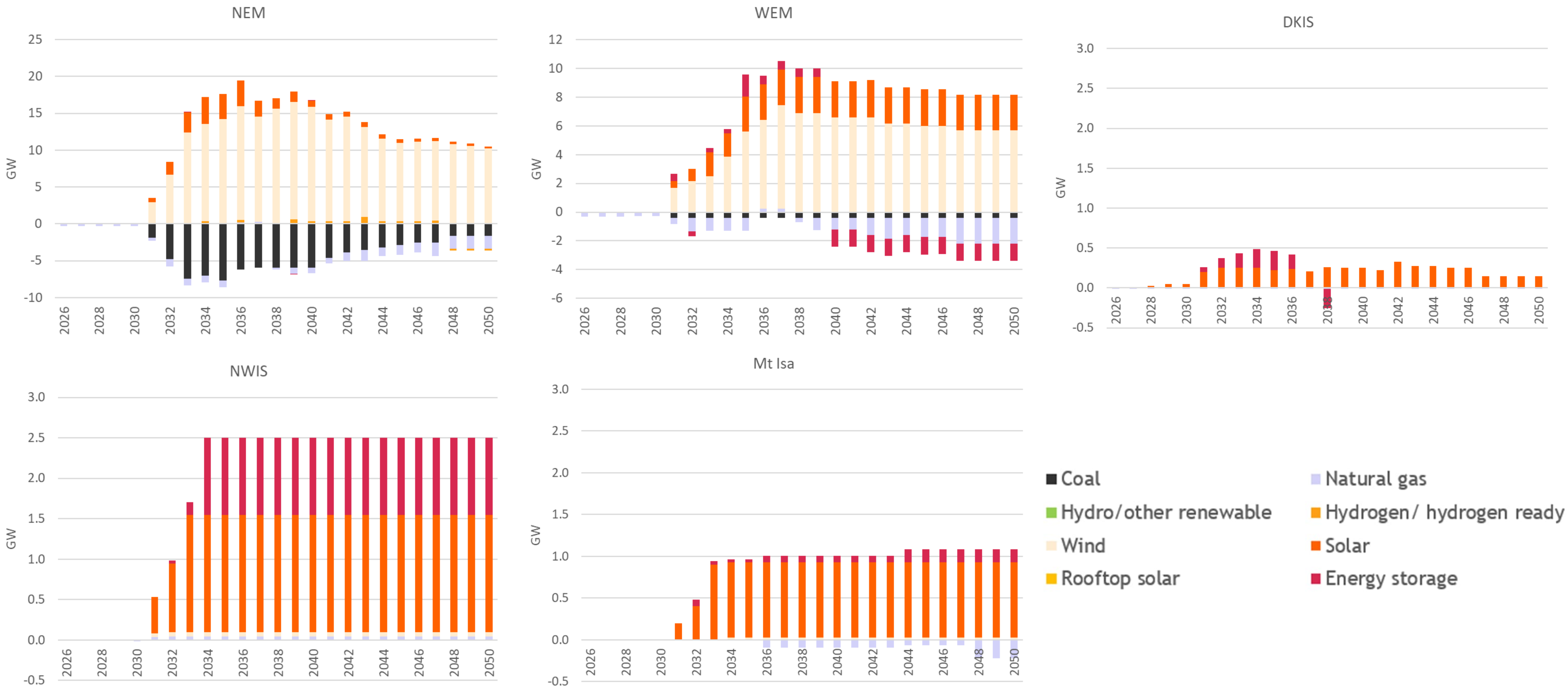


Figure C-4. Generation mix comparison, extended Safeguard Mechanism in 2 degree warming compared to reference scenario