The Impact of a Delayed Transition on Consumer Electricity Bills

Revision: Final report

Commissioned by the Clean Energy Council

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Jacobs

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Executive summary

The principal objective of this report is to establish the likely impact on consumer bills of a change in the amount of renewable capacity installed in the National Electricity Market (NEM) between the present day and 2030. Where renewable capacity build is reduced, the required capacity to meet customer needs is provided through the extension of coal fired generation capacity or the increased operation of gas-fired capacity. This impact is established in order to demonstrate the potential impact of a change in policy in relation to renewable build over the timeframe to 2030 and beyond to 2050, as part of a policy to instal nuclear power in the NEM towards the end of the 2030s.

The report explores the near to medium term bill impacts for consumers that flow from reducing renewable build in this timeframe. The report finds that a reduction in renewable build (compared to what is required to meet current Government targets) to 49 GW in 2030 means that retail bills for a representative residential consumer will ***increase by 30-41% in 2030***, or an additional ***$449-$606 per annum per household***.

We have explored a base case and two key scenarios in this report, to determine the impact of material reductions in renewable build on customer retail bills

- Base Case – AEMO ISP Step Change scenario. A view of the world in which current renewables objectives in relation to emissions reductions and renewable generation targets are met.
- Scenario 1 – Reduced renewables build. This scenario reduces renewable build investment in the run up to 2030, with 49.1 GW of installed renewables by 2030 compared to 72.7 GW in the base case scenario. Coal generation is extended while gas-fired generation provides the balance of energy required.
- Scenario 2 – Reduced renewables build and catastrophic coal plant failure. In this scenario, renewables are reduced as per scenario 1, with a major NEM coal-fired generation assumed to fail unexpectedly.

We then calculate how wholesale market impacts in these scenarios then translate into retail bills. The table below explores the increase in final retail bills, for a residential customer between the base case and each scenario.

Table 1. Retail bill impacts for NEM residential consumers, $ per customer per annum, 2030

Region	Scenario 1	Scenario 2	Scenario 1 %	Scenario 2 %
New South Wales	$339	$436	23.6%	30.3%
Queensland	$568	$729	37.2%	47.8%
South Australia	$407	$544	20.9%	27.9%
Tasmania	$731	$1,074	39.7%	58.4%
Victoria	$408	$614	31.9%	48.1%
NEM	**$449**	**$606**	**30.3%**	**41.0%**

Note: Percentage change when compared to AEMC 2024 Price Trends figures for 2030 in each state.

These increases are primarily driven by increased reliance on higher cost coal and gas generation, given the reduced renewable output available to the NEM.

A key consequence of a reduced renewable build in each scenario is that more gas must be burnt in gas generators, to provide enough electricity supply to meet demand. This gas comes at a significant additional cost.

The cost of gas purchased to supply the NEM in 2030 increases from $770m to between $2.3-$3.0bn putting significant pressure on the gas market during a period in which it is anticipated to be under supply demand pressure. Thermal plants, and gas plants in particular, play a much greater role in setting prices in the market where growth in renewable generation capacity is reduced.

The next section of this executive summary provides more detail regarding the modelling approach taken by Jacobs. Alternatively, click here to be taken directly to further detail of the modelling results.

Exploring a world that deviates from AEMO's integrated system plan.

The report uses as the baseline the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP), using the Step Change scenario. The Step Change scenario is currently deemed most likely by AEMO. In this scenario, government commitments and targets in relation to emissions reductions and renewables build targets are met. This plan involves maintaining the pace of investment in utility scale renewable resources in the NEM between now and 2050, coupled with ongoing investment by Australian energy consumers in electric vehicles (EVs), rooftop solar photovoltaic (PV), and home-installed batteries.

To test what might happen were the rate of utility scale renewable generation capacity build to be reduced significantly, the report uses the build trajectory from the recent report released by Frontier Economics titled *Economic analysis of including nuclear power in the NEM*. In this report, Frontier Economics reduced the build rate for renewables, in particular, onshore and offshore wind, utility scale solar and utility scale batteries, in a world where longer term, post 2035 nuclear capacity is installed to meet customer electricity needs.

This report does not make a longer-term assessment of the whole of system costs in the NEM of moving to nuclear power. It instead focuses on the short to medium-term effects of reducing renewable build, consistent with the assumptions described in the Frontier report.

A conservative scenario based approach to assessing medium term market outcomes

The Clean Energy Council commissioned Jacobs to undertake analysis that is conservative, considered and reasonable and based on transparent assumptions and methods. Jacobs in meeting this request has used industry and regulatory standard approaches to modelling future price outcomes in the NEM.

Forecasting price outcomes in the NEM is always challenging. The system is complex, and the further into the future the forecast is projected, the more subject it becomes to the assumptions underpinning a particular future view of the world and the behaviour of market participants in that future.

By focusing on a medium-term timeline and by employing a snapshot approach, looking at the 2030 financial year (FY) in detail, and running multiple scenarios for this year, we can test potential market outcomes under a multitude of potential futures.

In this report, we tested 100 potential price paths in FY 2030, to test outcomes under different market conditions, and gain greater confidence about the potential impact on consumers between 2025 and 2030.

The scenarios are constructed by using 5 different weather reference years to test different patterns of renewable output under different weather conditions. They are tested by using 10 different outage patterns for large thermal generators, to test the impact of large generators not being available during these periods. They are tested under average market demand conditions, a 1 in 2 demand year, and under higher demand conditions, a 1 in 10 demand year. This combination of 5 weather years, 10 different plant outage patterns, and 2 different demand scenarios combines to provide 100 different price projections for the 2030 financial year, in each major region of the NEM.

This approach of running multiple scenarios for any given year is consistent with the approach employed by the Australian Energy Market Commission (AEMC) in its projections of residential electricity price trends into the future and by the Australian Energy Regulator (AER) in its calculation of the electricity prices to be applied each year in the Default Market Offer (DMO) process.

Key generation capacity scenarios

Three key scenarios around the build of new plants and operation of existing plants are tested:

- Base Case – AEMO ISP Step Change scenario. A view of the world in which Commonwealth and State objectives in relation to emissions reductions and renewable generation targets are met. This involves significant investment in new capacity, both through the current Capacity Investment Scheme (CIS), and beyond the expiry of the scheme in 2030 to meet renewable generation targets.
- Scenario 1 – Reduced renewables build. This scenario reduces renewable build investment in the run up to 2030, to match the overall build for renewables set out by 2050 in the Frontier report. This results in 49.1 GW of installed renewables by 2030 compared to 72.7 GW in the base case scenario. The scenario then extends the operation of coal fired stations in the NEM, beyond the timeline observed in the Base Case, to allow for the full technical operating life of these stations and agreed closure dates where applicable. This scenario then allows gas-fired generation to provide the balance of energy required in the system.
- Scenario 2 – Reduced renewables build and catastrophic coal plant failure. In this scenario, the same build restrictions are applied as in Scenario 1, and existing coal plants are extended to the end of their technical life or agreed operating timeframe, but in addition, a major NEM coal-fired generation asset is assumed to fail unexpectedly. This scenario is applied to test the potential impact of similar market events as were observed in 2021 following the Callide C explosion, which led to a greater reliance on gas generation assets to meet the energy needs of Australian electricity consumers. This scenario tests the impact of a similar incident occurring amidst a backdrop of lower renewables build.

The main difference between the scenarios is the extent of renewable generation technology build.

The NEM in 2024-25 has 26 GW of renewable generation according to AEMO's ISP, with 3.5 GW of utility scale storage, 13 GW of wind and 9.5 GW of utility scale solar. This is out of a total of just over 65 GW of grid scale generation capacity.

Under the Base Case, 26 GW of renewable generation grows to 72.7 GW by 2030. This is consistent with the projections of the ISP.

Under the slower renewables build applied to Scenarios 1 and 2, this is restricted to 49.1 GW by 2030, as seen in Table 2 below. These figures approximate the build path projected in the Frontier Economics report.

Table 2. Generation capacity under scenarios (GW)

Scenario	Base Case	Scenario 1	Scenario 2
Year	**2030**	**2030**	**2030**
Wind	39.3	21.5	21.5
Offshore Wind	-	-	-
Large Solar	15.6	15.6	15.6
Large Battery	17.9	11.9	11.9
Total Renewable	**72.7**	**49.1**	**49.1**
Coal	11.4	16.3	15.1*

* Reduction from Scenario 1 due to catastrophic failure removing 1.2 GW.

In these scenarios, coal-fired generating assets are assumed to operate for longer than they do so under the ISP Step Change scenario. Instead of only 11.4 GW operating in 2030, by extending the operation of plants to their technical life or agreed operating timeframe, 16.3 GW of coal-fired capacity is available in scenario 1. After removing a station in scenario 2, 15.1GW of coal generation is available.

Extending the life of coal-fired generation capacity can have implications for the reliability of these plants as they near the end of their technical life. International studies and data available for the NEM suggests these plants becomes much less reliable the older they get[1]. To allow for this, where the operation of a coal plant has been extended under Scenarios 1 and 2, we progressively increase the amount of full and partial outages[2] experienced by these stations. This is done conservatively, by increasing full outage rates by 1% for every year leading up to the year prior to plant retirement. For partial outages, outage rates are increased by 2% every year leading up to the last year of operation prior to retirement.

Gas generation is also required to operate more frequently under scenarios 1 and 2. This will create increased demand for gas, in a 2030 market that is already forecast to be under supply pressure, given the decline of existing gas production fields in the east coast gas market and the lack of replacement of this capacity with new fields under development.

We therefore assume that east coast gas market pricing dynamics are materially impacted due to the additional gas generation required in scenarios 1 and 2. These increases in demand for gas from gas powered generation translate to a requirement for more expensive sources of gas supply to come online including in this case, liquefied natural gas (LNG) import.

We therefore assume LNG import benchmarks tend to set the gas market price, versus export benchmarks. Additional requirements are also made of peaking gas infrastructure under these scenarios. To reflect the above in the model, we apply a $2/GJ price uplift in Scenarios 1 and 2 to all gas-fired stations in the NEM, to allow for the impact of increased gas-fired generation on the gas market and the need for more expensive sources of gas supply.

These scenarios for the future of the NEM are then solved in the PLEXOS linear programme. This is a widely used industry software programme used by Jacobs for the assessment of project feasibility studies for clients, and by various market bodies and market participants to forecast the future operation of the system and future wholesale prices.

Report findings

The focus of our analysis has been on the wholesale price impacts associated with reducing utility scale renewable build to 2030. The wholesale component of retail bills is the main bill component affected over the timeframes explored in this analysis.

Jacobs' analysis of wholesale price changes between the Base Case and Scenarios 1 and 2, shows increases in wholesale spot prices in Scenarios 1 and 2 versus the Base Case. This is driven by the greater role for ageing thermal coal plants and gas generation in providing the balance of energy to the market that is removed through the reduced renewables build. Coal and gas play a much greater role in these scenarios in providing energy and peaking supply capacity to the market than they do in the Base Case.

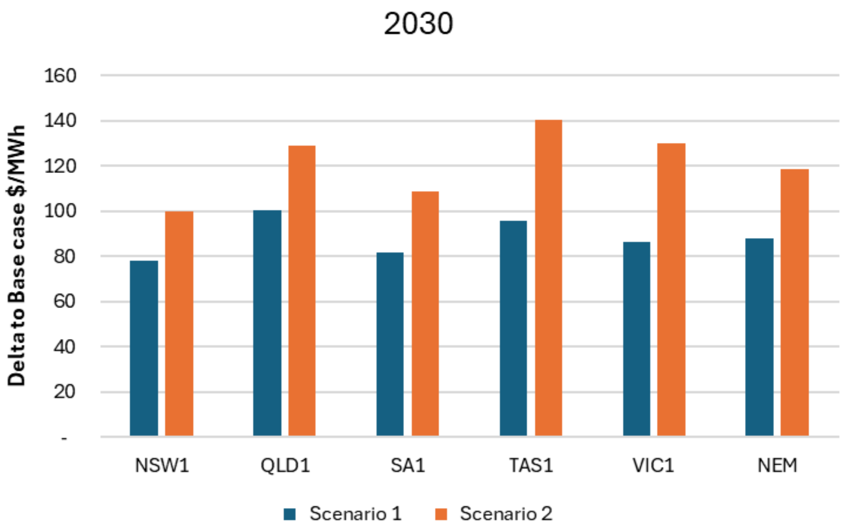
In Scenario 1 across the 100 scenarios analysed, wholesale energy prices increase by $88/MWh on average in 2030. In Scenario 2, they increase by $118/MWh in 2030.

This price uplift occurs on average (i.e. across the mean price outcome) in all scenarios. Figure 1 below illustrates the wholesale spot price changes in more detail.

[1] Discussed in: The challenge of ageing coal generators and the growing role of storage in grid reliability, Baringa Partners analysis for Climate Council, December 2024.

[2] Generating plant outages can be partial or full in nature. A partial outage is where a plant is still capable of generating electricity, but at a reduced capacity, whereas a full outage is where a plant is rendered completely unable to generate electricity. Outages can be planned, for maintenance purposes, but can also occur unplanned, due to factors including equipment failure, power outages and extreme weather conditions.

Figure 1. Wholesale spot price increases from base case relative to scenarios



Jacobs translates wholesale spot price changes in $/MWh to c/kWh impacts on retail bills. A $10/MWh wholesale price impact is assumed to have a 1 ckwh retail bill impact. Jacobs make no other changes to other parts of the bill and use the change in wholesale spot prices as an indication of the change in the cost of wholesale energy in retail bills. Other components of the bill, not modelled here, include network costs, environmental scheme costs and retail costs.

The changes in wholesale costs are compared to total bill costs in ckwh for the financial year 2030 for each region of the NEM, as provided in the AEMC's 2024 residential electricity price trends report.[3] The AEMC conducted this analysis of total bill costs in the NEM using AEMO's ISP Step change scenario as its basis. Jacobs base case price paths, i.e. the 100 price paths reflecting the build pattern under the ISP Step change scenario, broadly capture and are consistent with wholesale costs published in the AEMC report for the financial year 2030. Retail bill impacts in % terms are therefore shown as a % difference to the AEMC's 2030 figures.

The impact of the wholesale price changes seen in Figure 1 on the final retail bill in 2030 is significant.

Under Scenario 1, where coal capacity is kept on for longer than what was deemed least cost under the AEMO ISP Step Change scenario and new renewable capacity is reduced accordingly, ***residential electricity bills are likely to increase by 30%*** on average across the NEM in 2030 due to the impacts on the wholesale market. This would amount to an increase of ***$449 per annum for a representative consumer*** across the NEM. This impact varies from state to state.

Under scenario 2, which expands on scenario 1 by removing a large coal fired generator from operation, the impact of reduced renewable capacity results in ***increases of residential electricity bills by 41%*** on average across the NEM, or ***$606 per annum for a representative consumer*** across NEM regions.

[3] AEMC, Residential Electricity Price Trends, 2024. https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024

Table 1. Retail bill impacts for NEM residential consumers, $ per customer per annum, 2030

Region	Scenario 1	Scenario 2	Scenario 1 %	Scenario 2 %
New South Wales	$339	$436	23.6%	30.3%
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NEM	**$449**	**$606**	**30.3%**	**41.0%**

Note: Percentage change when compared to AEMC 2024 Price Trends figures for 2030 in each state.

A representative small business customer (with an annual usage of 10,000kWh[4]) is likely to experience a $877 increase in their bills under scenario 1 and a ***$1,182 increase in their bill*** under scenario 2 across the NEM.

Table 3. Retail bill impacts for NEM small business customers, $ per customer annum, 2030[5]

Region	Scenario 1	Scenario 2
New South Wales	$778	$1,000
Queensland	$1,006	$1,290
South Australia	$815	$1,088
Tasmania	$954	$1,401
Victoria	$862	$1,298
NEM	$877	$1,182

Outcomes under more difficult conditions

Power systems and wholesale market outcomes are affected by various conditions and events, particularly generation outages, weather events and levels of customer demand. Sometimes these conditions can be extreme relative to average conditions, such as periods of extremely hot weather combined with higher than normal demand.

Under these more extreme conditions, the power system can be challenged, with tight supply demand balances driving up wholesale prices. This can put further pressure on retail bills.

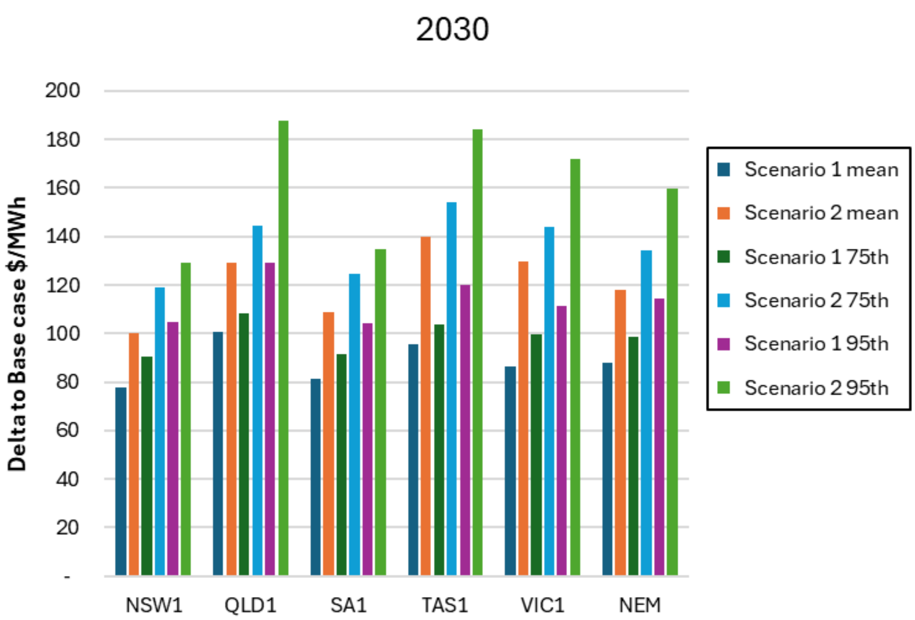
These more extreme conditions are less likely to occur than more moderate conditions. However, they are not impossible and, if they were to occur in a system with markedly less renewables, can have significant impacts on final retail bills.

[4] The annual usage of a representative small business customer is taken to be 10,000 kWh, in alignment with the representative annual usage used in the calculation of the Default Market Offer (DMO) 6.

[5] Percentage increase in the retail bill results are based on comparisons with the AEMC's 2024 residential price trends work. However, there were no SME bills calculated in the AEMC's work hence no percentage comparisons are made here. However we expect that percentage changes in SME bills would be broadly consistent with those we have found for residential bills.

The development of 100 price paths based on differing assumptions in relation to weather, demand and generator outages allows us to analyse price differences also at the 75th percentile[6] and the 95th percentile of outcomes. These help to illustrate price differences under more challenging conditions that can occur, such as extreme weather outcomes and elevated demand.

Figure 2. Wholesale price outcomes at mean, 75th and 95th percentiles



Analysis of the 75th and 95th percentile price deltas in ***scenario 1*** would see potential wholesale spot price increases between $99/MWh and $114/MWh. Were this to flow through to retailer contracting costs, the potential impact on ***consumer bills would see residential bills rise by $503-$584 per household***.

Analysis of the 75th and 95th percentile of price deltas in ***scenario 2*** would see potential wholesale spot price increases between $135 and $160/MWh. The potential impact on ***consumer bills would see residential bills rise by $688-$824 per household***.

Transmission costs

Changes in the extent of renewable build prior to 2050 have a bearing on transmission investment and transmission projects that would be developed to help bring new sources of generation to market.

Our analysis, in focusing on FY 2030, would likely see little change in transmission build, and therefore no material changes in retail bills for consumers, in this timeframe as a consequence of any change in renewable build-out. Much of the transmission investment occurring between 2025 and 2030 is either already under way, or likely to proceed regardless of decisions made in 2025 and 2026 in relation to the pace of renewables developments. This is because many new transmission projects are intended to help address existing issues of congestion in the NEM.

For the purposes of this analysis, potential changes in transmission costs associated with the change in renewables build between 2025 and 2030 are not assumed to have a material impact on end user bills.

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[6] Our market modelling develops 100 price paths to explore 100 different possible worlds, reflecting various combinations of key factors like demand levels and weather events. Wholesale market prices created in these different worlds – from more benign to more extreme – can then be plotted. The 75th percentile price therefore denotes the 75th highest price difference between scenario 1 and the base case. For context, forecasts of retailer costs prepared by the AEMC for their residential price trends analysis and by the AER for the development of the Default Market Offer (DMO) have drawn on wholesale price outcomes at the 75th percentile and 95th percentile in determining retailer wholesale costs.

The gas market

The gas supply demand balance on the east coast of Australia is fast evolving, with AEMO's Gas Statement of Opportunities (GSOO) showing gas shortfalls in the latter half of the current decade. A scenario with lower renewable generation that relies more on gas powered generation to meet consumer electricity needs is likely to see significantly more gas used.

Under scenario 1, with less renewable energy and a greater reliance on gas, gas consumption for power generation increases significantly from 63 PJ to 211 PJ per annum. This would likely further impact the gas market with a bearing on the price of gas supplied to gas generators.

The analysis accounts for this change by considering the effects of moving gas market pricing from LNG ***export parity*** (where the gas price is set by reference to the cost of additional volumes of gas for domestic use in Australia from LNG exporters in Queensland), to LNG ***import parity*** (where LNG gas import is increasingly relied on to meet domestic needs for gas). Such a change in supply demand and gas price dynamics may lead to gas price increases in the domestic gas market.

A greater reliance on gas powered generation will likely place a greater strain on existing gas infrastructure in the east coast gas market, including gas transmission pipelines and gas storage facilities, as this infrastructure is called on to provide greater volumes and greater gas delivery capacity to meet winter and summer peaks in electricity demand.

Given the above factors, the analysis assumes a price uplift of $2/GJ on gas fired generators in the NEM, in the scenarios with lower renewable energy, and a greater reliance on gas generation.

The cost of gas purchased for gas generators increases to $2.3-$3 billion in scenarios 1 and 2 with less renewable generation, versus $770 million in the base case.

Limitations

Any forecast of prices in the NEM is a representation of the set of assumptions used in the compilation of that forecast. Changes in relation to electricity demand, coal retirement dates, oil and gas prices, the installation of consumer energy resources by households, all have a significant bearing on these results.

However, the snapshot analysis approach, with 100 price paths, examining two scenarios under several different operating assumptions for the NEM, helps to address some of these limitations. The exchange of low-cost renewable energy resources for high-cost coal and gas resources has a significant impact on the cost of energy, the price of energy established through settlement of the market, and the volume of emissions associated with the delivery of that energy.

Important note about this report

The sole purpose of this report and the associated services performed by Jacobs is to assist the Clean Energy Council to understand consumer pricing issues relating to the potential reduction in the build of renewable resources in the NEM as compared to the current AEMO Integrated System Plan Step Change scenario.

In preparing this report, Jacobs has relied upon information that is publicly available and/or provided by the Client. Except where stated in the report, Jacobs has not verified the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate, or incomplete then it is possible that the observations and conclusions in this report may be incorrect. Additionally, the passage of time, manifestation of latent conditions, or impacts of future events may require re-evaluation of the outcomes presented in this report.

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1. Introduction

The principal objective of this report is to establish the likely impact on consumer bills of a reduction in the total build of utility scale, [7] grid connected, large scale renewable resources in the National Electricity Market (NEM). Renewable generation includes large scale solar photovoltaic (PV), wind and utility scale batteries.

The report focuses on the impact of this reduction in renewables on wholesale components of the bill. Wholesale refers to the wholesale market for electricity generated in the NEM, or the wholesale price of energy generated by renewable and thermal generators in the NEM. The wholesale component of consumers bills is the component of the bill where the greatest degree of change has been observed historically, and is observed in forward-looking forecasts, for example the Australian Energy Market Commission's (AEMC) *2024 Residential Electricity Price Trends* report, which provides a ten-year outlook for consumer bills across the NEM.[8]

This report looks at medium-term impacts over a five-year timeframe for consumers, specifically reviewing the impacts on consumer bills at a single point in time, the 2029/2030 financial year.

The report does not consider longer-term cost differences to 2050 and beyond of different policy considerations in relation to nuclear power and the implications of such differences for generation investment costs, the wholesale market and related transmission investment. Rather, it explores the short term impacts on retail bills, if renewable build out is reduced in a manner consistent with the assumptions described in the Frontier report – *Economic analysis of including nuclear power in the NEM*. The conclusions of the report are therefore aimed at stating what the consumer bill impacts will be of a slowdown in renewable energy build over the medium term and the replacement of this generation with existing thermal sources such as coal and gas. The analysis ensures all NEM demand is met in the timeframe without any breach of the reliability standard, which requires that at least 99.998 per cent of forecast customer demand is met in each region in each year of the analysis.

The sections that follow cover the following:

- Chapter 2: Method
- Chapter 3: Assumptions
- Chapter 4: Results
- Chapter 5: Conclusions
- Appendix: Residential Electricity Power Bills

[7] 'Utility scale' refers to generators and storage assets including wind, solar and (pumped) hydro power stations, typically larger than 30MW, connected to the high voltage transmission and distribution network. The term is used to distinguish from 'small scale' assets, such as Consumer energy resources like rooftop PV and household batteries, or small-scale generation and storage connected to the low voltage distribution network.

[8] AEMC, Residential Electricity Price Trends, 2024. https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024

2. Method

Jacob's analysis of the impact of a slowdown in renewables build on consumer bills focuses on the wholesale component of the consumer bill. This is the most responsive portion of the bill to changes in policy outcomes over the next five years.

2.1 Wholesale market analysis

Jacobs models the wholesale price impact for the five regional reference price regions of the NEM, including Queensland, New South Wales, Victoria, South Australia and Tasmania. Western Australia and the Northern Territory are not modelled.

Jacobs estimate the impact of changes in the build of renewable capacity in the NEM by simulating dispatch outcomes in the future NEM through using the PLEXOS linear programme to forecast spot prices in each region of the NEM for every thirty minutes taken as a snapshot of the future financial year 2029-30.

This is modelled over two different future build scenarios for the NEM as noted below. These build scenarios are created by reducing grid connected renewables build and then replacing this with thermal capacity, either through the extension of the operating life of coal generators where their technical life allows for this, or through the increased operation of gas fired generation capacity. This thermal capacity is relied on such that on dispatch, the amount of unserved energy (USE) in the system does not violate the reliability standard. The reliability standard requires that we have enough electricity supply to meet demand 99.998 per cent of the time, in every region in every financial year.[9]

Once the build profile is established for the three scenarios, each scenario is run in the PLEXOS program under five different reference years (or five different weather patterns that drive renewable generation), the two demand settings of POE50 and POE10 (POE50 representing average demand and POE10 more extreme demand which would only be exceeded one year in 10) and under 10 different random outage patterns for thermal generators.

This provides us with 100 price paths for comparison between each of the key scenarios. These price paths can be used, at the median, 75th and 95th percentile to understand the potential impact of these changes on a retailers cost of contracting power for supply to retail customers. This cost is then the cost that would be passed through to consumers, impacting bills over this timeframe.

2.1.1 Scenarios

Three potential futures for the NEM are modelled. The Base Case assumes renewable capacity is built according to AEMO's 2024 Integrated System Plan (ISP) Step Change scenario. Scenario 1 then explores a reduction in the build-out of utility scale renewables when compared to the base case. Scenario 2 then assumes the same cap in utility scale renewables build but with the additional consideration of a large coal-fired plant failing unexpectedly in 2030.

The base case and scenarios are summarised as follows and expanded below:

- **Base Case**: ISP Step Change scenario. This scenario reflects a pace of energy transition that supports Australia's contribution to limit global temperature rise to less than 2 degrees Celsius. Through AEMO's consultation process for the ISP, it is deemed the most likely future scenario for the NEM.
- **Scenario 1**: Build-out of grid-scale renewables is reduced to 49.1 GW in 2030 and coal generation is extended compared to the Base Case.

[9] https://www.aemc.gov.au/sites/default/files/2020-03/Reliability%20Standard%20Factsheet.pdf

- **Scenario 2**: Build-out of grid-scale renewables is slowed down and coal generation is extended compared to the Base Case. An unexpected large scale coal plant failure is modelled to reflect the impact of a greater reliance on ageing coal-fired generators through this period.

The base case and scenarios are described in more detail below.

2.1.2 Base Case

The Base Case reflects AEMO's Integrated System Plan of 2024, which adopts the Step Change scenario for the grid build-out and market dynamics of the NEM for the next 25 years. This scenario assumes the federal target of achieving 82% renewable energy generation in the NEM by 2030 is met, and that Australia transitions to a net-zero economy by 2050. To meet these targets, the scenario calls for investment which would triple grid-scale variable renewable energy (VRE) capacity by 2030 and increase it six-fold by 2050. 90% of coal capacity would be retired by 2035, with the remainder retired by 2040. Gas generation increases slightly after 2030 to meet the firming requirements for the grid (peaking at 4% of total electricity generation).

2.1.3 Scenario 1

Scenario 1 makes changes to the Base Case to reflect a future where the renewable energy build-out is greatly reduced, coal generation is extended and gas plants must run harder to supply consumers with energy and the NEM prepares to integrate nuclear power post 2030.

Frontier Economics released two reports in December 2024 covering the integration of nuclear power in the NEM. Frontier Economics, *Report 2 – Economic Analysis of including nuclear power in the NEM* details the resulting costs, capacity and generation changes, and emissions, of integrating nuclear power into the NEM from 2036 onwards. One of the assumptions applied in this analysis is that coal-fired generators are progressively replaced by nuclear power stations. For nuclear power stations to replace these coal generators without a shortfall in dispatchable power in the interim, the retirement dates of these coal plants, as listed in the ISP Step Change scenario, are extended. The report also assumes a greatly reduced renewable generation build-out in the lead up to 2051.

In Scenario 1, the build trajectory between 2025 and 2051 from *Table 2: Nuclear alternative – step change*, from Frontier Economics Report 2, is used.[10] No nuclear power capacity is included given our analysis only covers the 2030 financial year. However, coal generator retirement dates are extended. Table 2 from Frontier Economics Report 2[11] shows a total renewables build by 2051 of 82.7 GW, with 47 GW of wind, 24.8 GW of solar and 10.9 GW of utility scale battery. This cap impacts the build of renewable capacity by 2030 such that the build limit of 82.7 GW is achieved by 2051. This has the effect of reducing renewable capacity built by 23.6 GW by 2030.

The reduced renewable build corresponds to achieving 54% of energy from renewable energy by 2030, short of the federal target of 82%. Demand for electricity is still projected to increase in Scenario 1 in line with the Base Case. That is, the trends in electrification and electrical vehicle (EV) growth inherent in the Step Change scenario are assumed to prevail thereby increasing electricity demand.

Scenario 1 incorporates increased outage rates for coal generators in the five years leading up to their (delayed) retirement. This assumption has been included:

- To account for the fact that when coal generators approach the end of their technical life, the equipment within the plants becomes more unreliable, and more prone to outages.

[10] Frontier Economics, Report 2 – Economic analysis of including nuclear power in the NEM, p.22.

[11] Ibid.

- Since there is reduced VRE capacity under this Scenario for the same demand, thermal generators (including coal generators) will be pushed to operate more than they would have in the Base Case, putting greater strain on these units than would otherwise be the case.

2.1.4 Scenario 2

Scenario 2 incorporates the same build assumptions as Scenario 1 but includes a future where there is an unexpected catastrophic failure of a large coal plant in 2030. Catastrophic failures, while infrequent, are observed in the NEM's recent history. On 25 May 2021 Unit C4 of the Callide C Power Station (CPP) failed, resulting in an explosion and substantial damage to the unit[12]. Shortly afterwards Callide's other operating units tripped and went offline[12]. Unit C4 (maximum capacity 420 MW) was re-commissioned over 3 years later on 30 August 2024[13]. Callide C Power Station has a total maximum capacity of 844 MW, and the catastrophic failure causing all units to go offline resulted in significant, long-term, and wide-ranging impacts on energy consumers in Queensland and the NEM as a whole[14].

Scenario 2 explores the effects of relying on thermal generation for longer. While catastrophic failure of coal generators can occur under any scenario where coal is operating, the operation of coal plants in Scenario 1 where coal generators operate for longer and at higher capacity factors increases the likelihood of events like this occurring.

In Scenario 2, the unexpected catastrophic failure of a coal plant is tested in 2030. The plant selected is a large coal-fired power station, whose failure would result in 1.2 GW of capacity removed from the NEM during the modelled year.

2.1.5 Consistent assumptions between these scenarios

Figure 2-1 below shows information on committed and anticipated generators from AEMO as at October 2024. There is 23.6 GW of committed and anticipated capacity in the NEM, 12.2 GW committed and 11.4 GW anticipated. 8.4 GW is battery storage, 3.5 GW is wind and 6.2 GW is Solar. This generating capacity is included in all three scenarios modelled.

Figure 2-1. NEM Generation information October 2024

	Fuel - Technology Category										
Summary Status	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water	Biomass	Battery Storage	Other	Total
Existing	21,255	2,960	7,270	1,948	9,628	11,634	7,979	412	2,163	143	65,391
Announced Withdrawal	2,880	180	158	800	-	-	-	-	-	-	4,018
Existing less Announced Withdrawal	18,375	2,780	7,112	1,148	9,628	11,634	7,979	412	2,163	143	61,373
Upgrade / Expansion	-	-	-	-	-	-	-	-	-	-	-
Committed	-	-	750	-	2,606	2,643	2,450	-	3,759	-	12,207
Anticipated	-	-	204	-	3,639	894	1,998	-	4,686	-	11,421
Proposed	990	207	2,864	1,717	51,481	114,732	19,271	333	98,481	4,804	294,880

2.1.6 Differences between the scenarios

Table 2-1 shows the differences between the Base Case and the two modelled Scenarios.

[12] https://www.csenergy.com.au/what-we-do/thermal-generation/callide-power-station/c4recovery

[13] https://www.csenergy.com.au/news/callide-unit-c4-returns-to-service

[14] https://www.aer.gov.au/news/articles/news-releases/callide-power-trading-penalised-9-million-not-meeting-performance-standards

Table 2-1. Generation capacity build under scenarios (GW)

Scenario	Base	Scenario 1	Scenario 2
Year	**2030**	**2030**	**2030**
Wind	39.3	21.5	21.5
Offshore Wind	-	-	-
Large Solar	15.6	15.6	15.6
Large Battery	17.9	11.9	11.9
Total Renewable	**72.7**	**49.1**	**49.1**
Coal	11.4	16.3	15.1*

*Reduction from Scenario 1 due to catastrophic failure removing 1.2 GW.

2.2 Retail bill impact calculation

Differences in the cost of wholesale energy between these scenarios are used to assess the potential overall impact on consumer bills.

Costs in $/MWh terms are converted to c/kWh. Then representative consumer demand patterns are used and applied to the change in wholesale costs in c/kWh to arrive at overall $ impacts for a typical consumer.

Table 2-2. Representative residential consumer demand

Region	kWh
Tasmania	7,666
South Australia	5,000
Victoria	4,727
New South Wales	4,362
Queensland	5,650

Source: AEMC 2021 Residential Electricity Price Trends

Percentage changes in overall consumer bills are calculated with reference to 2024-25 AER DMO figures.

3. Assumptions

3.1 Wholesale market assumptions

3.1.1 Coal retirement dates

In the Base Case, the coal retirement dates will be taken from AEMO ISP Step Change scenario.

In Scenarios 1 and 2, to prepare the NEM for nuclear power and to allow for the impacts of lower renewable build on reliability or unserved energy, coal plants have been extended as much as possible to meet the reliability standard and provide the NEM with sufficient energy and dispatchable power.

Coal plants in Scenarios 1 and 2 have been extended according to the following criteria:

- Back to any formally announced dates, including via government agreement or company statement; then
- To the specified technical life of the plant, where provided in published statements; or
- If the technical life of the plant was unclear, the retirement year used in the AEMO Inputs, Assumptions and Scenarios Report (IASR), which normally does not exceed the conservative technical life assumption of 50 years.

Applying these criteria results in the extension of retirement dates of 13 out of 15 of the coal plants currently operating in the NEM. The following coal plant units have pre-2030 retirement dates in the Base Case, which have been extended past 2030 in Scenarios 1 and 2:

- Bayswater Power Station units 1 & 2 (BW01 and BW02)
- Vales Point Power Station all units (VP5 and VP6)
- Gladstone Power Station units 1, 2 and 3 (GSTONE1, GSTONE2 and GSTONE3)
- Stanwell Power Station units 1 & 2 (STAN1 and STAN2)
- Loy Yang B Power Station unit 1 (LOYYB1).

An agreement between the NSW government and Origin Energy allows Eraring to operate until 19 August 2027, with the plant to retire in full no later than April 2029. Eraring is therefore excluded from FY30. Additionally, EnergyAustralia has an agreement with the Victorian Government to close Yallourn Power Station in mid-2028, so Yallourn is also excluded from the modelled year.

Table 3-1 shows the ISP Step Change coal retirement dates, to be used in the Base Case, alongside the updated coal retirement dates, used to compensate for the reduced renewables build in Scenarios 1 and 2.

Figure 3-1. Difference in coal capacity between the Base Case and Scenarios 1 & 2

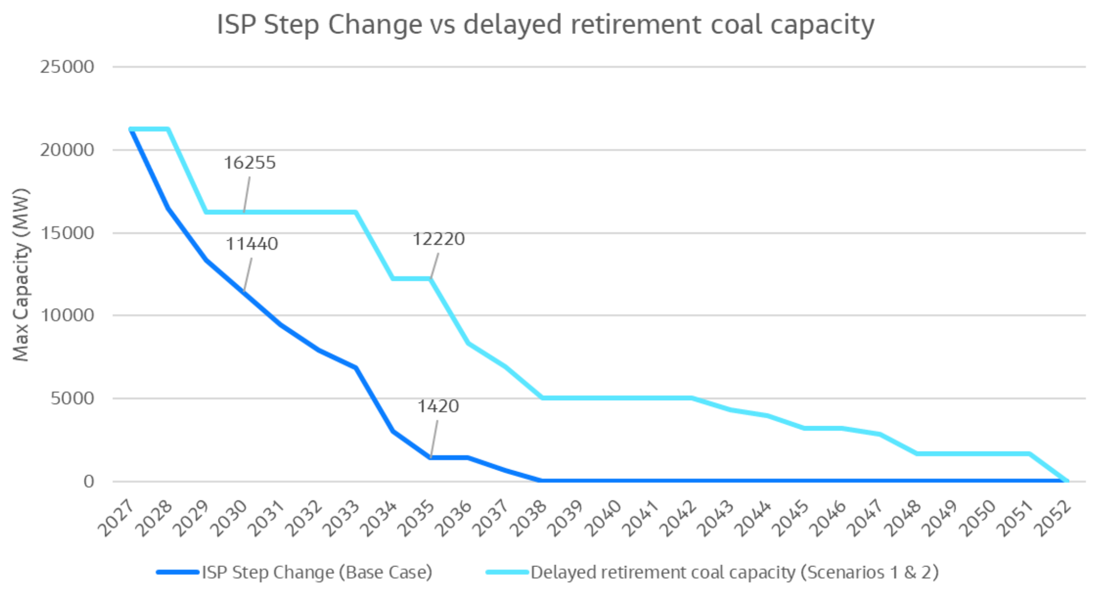


Table 3-1. Modelled coal retirement dates[15]

Region	Station	ISP step change coal retirement dates (Base)	Updated coal retirement dates (Scenarios 1 and 2)	Extension
Black Coal NSW	BW01	1/07/2029	1/07/2033	4 years
Black Coal NSW	BW02	1/07/2029	1/07/2033	4 years
Black Coal NSW	BW03	1/07/2030	1/07/2033	3 years
Black Coal NSW	BW04	1/07/2031	1/07/2033	2 years
Black Coal NSW	ER01	1/08/2027	1/08/2028	1 year
Black Coal NSW	ER02	1/08/2027	1/08/2028	1 year
Black Coal NSW	ER03	1/08/2027	1/08/2028	1 year
Black Coal NSW	ER04	1/08/2027	1/08/2028	1 year
Black Coal NSW	MP1	1/07/2036	1/07/2036	-
Black Coal NSW	MP2	1/07/2037	1/07/2037	-
Black Coal NSW	VP5	1/07/2028	1/07/2033	5 years
Black Coal NSW	VP6	1/07/2028	1/07/2033	5 years
Black Coal QLD	CALL_B_1	1/07/2027	1/07/2028	1 year
Black Coal QLD	CALL_B_2	1/07/2027	1/07/2028	1 year
Black Coal QLD	CPP_3	1/07/2033	1/07/2051	18 years
Black Coal QLD	CPP_4	1/07/2033	1/07/2051	18 years
Black Coal QLD	GSTONE1	1/07/2027	1/07/2035	8 years
Black Coal QLD	GSTONE2	1/07/2029	1/07/2035	6 years

[15] In the Base Case, closure dates for all coal units were obtained from the AEMO ISP Step Change model, sourced from the Step Change model file.

Black Coal QLD	GSTONE3	1/07/2029	1/07/2035	6 years
Black Coal QLD	GSTONE4	1/07/2030	1/07/2035	5 years
Black Coal QLD	GSTONE5	1/07/2030	1/07/2035	5 years
Black Coal QLD	GSTONE6	1/07/2031	1/07/2035	4 years
Black Coal QLD	KPP_1	1/07/2034	1/07/2042	8 years
Black Coal QLD	MPP_1	1/07/2034	1/07/2051	17 years
Black Coal QLD	MPP_2	1/07/2034	1/07/2051	17 years
Black Coal QLD	STAN-1	1/07/2027	1/07/2043	16 years
Black Coal QLD	STAN-2	1/07/2028	1/07/2044	16 years
Black Coal QLD	STAN-3	1/07/2032	1/07/2044	12 years
Black Coal QLD	STAN-4	1/07/2032	1/07/2046	14 years
Black Coal QLD	TARONG#1	1/07/2030	1/07/2036	6 years
Black Coal QLD	TARONG#2	1/07/2030	1/07/2036	6 years
Black Coal QLD	TARONG#3	1/07/2032	1/07/2037	5 years
Black Coal QLD	TARONG#4	1/07/2033	1/07/2037	4 years
Black Coal QLD	TNPS1	1/07/2033	1/07/2037	4 years
Brown Coal VIC	LOYYB1	1/07/2027	1/07/2047	20 years
Brown Coal VIC	LOYYB2	1/07/2031	1/07/2047	16 years
Brown Coal VIC	LYA1	1/07/2033	1/07/2035	2 years
Brown Coal VIC	LYA2	1/07/2033	1/07/2035	2 years
Brown Coal VIC	LYA3	1/07/2033	1/07/2035	2 years
Brown Coal VIC	LYA4	1/07/2033	1/07/2035	2 years
Brown Coal VIC	YWPS1	1/07/2028	1/07/2028	-
Brown Coal VIC	YWPS2	1/07/2028	1/07/2028	-
Brown Coal VIC	YWPS3	1/07/2028	1/07/2028	-
Brown Coal VIC	YWPS4	1/07/2028	1/07/2028	-

3.1.2 Generator outage rates

Outages in black and brown coal generating capacity are periods in which these plants are not operational or not available to produce electricity to their full design or normal operating capacity. Outages can be planned or unplanned. Planned outages refer to periods in which coal stations are out for scheduled maintenance. Unplanned outages refer to unexpected shutdowns or reductions in power output due to faults or issues at the station.

The availability of brown and black coal generation capacity in the NEM has a bearing both on average prices over weekly and monthly timeframes and on high priced events on peak demand days. Unplanned outages can have a greater impact than planned outages given the market has a shorter period to respond. Where brown and black coal are not available, their generation capacity is most likely to be replaced by more expensive higher priced capacity available to the NEM to meet customer load at any point in time. Gas generation, utility scale battery capacity and hydro generation would ordinarily replace unavailable coal capacity, particularly in peak demand periods.

In recent periods, AEMO have observed the impact of declining black and brown coal availability in driving higher prices and an increase in high priced events.[16] The older coal stations are, and the longer their life is extended, in particular where close to their technical life, the more prevalent full and partial outages of coal capacity become. A generation fleet which relies increasingly on ageing thermal coal plants may be subject to more unexpected high price events, than if that capacity was taken out of service and replaced by alternative dispatchable capacity.

Below, Jacobs explain the treatment of coal outage rates under the different future scenarios of the NEM. Given the life of some coal stations is extended further in the future with a lower renewables build, these outage rates have a greater bearing on prices in the delayed transition scenarios.

Base Case

Existing generator outage rates are based on the most recent four years of outage data as outlined in the 2024 ISP, 2023 IASR assumptions workbook.

Figure 3-2. Outage rates from the 2023 IASR assumptions workbook

Existing generators Outages (Outage rates for year 2023-24)

Fuel type	Forced Outage Rate (%)		Mean time to repair (hrs)		Partial Outage Derating Factor (%)
	Full outage (% of time)	Partial outage (% of time)	Full outage	Partial outage	
Brown Coal	7.75%	11.56%	90.05	12.20	17.91%
Black Coal NSW	6.31%	31.46%	157.62	33.97	16.60%
Black Coal QLD	6.75%	12.86%	185.00	56.42	25.16%
OCGT	7.21%	1.12%	44.08	106.48	9.99%
Small peaking plants	9.58%	0.32%	150.20	189.52	33.70%
Hydro	5.11%	1.71%	38.10	473.44	15.18%
CCGT + Steam Turbine	5.04%	1.66%	61.19	40.35	15.21%
Batteries	1.84%	-	26.05	-	-

Scenarios 1 and 2

Jacobs uses an uplift in outage rate for coal plants in the five years up to their retirement. This increase in outage rate is to be applied to the coal stations under Scenarios 1 and 2 where the life of coal assets is extended to cover the fall in renewable build rates assumed under those scenarios.

The outage rate increase is based on full forced outage rate data from older plants in the NEM, as well as international data on the outage curve as it relates to ageing plants. The forced outage rate for partial outages was increased proportionally to the forced outage rate for full outages – in AEMO's IASR, the partial forced outage rate is around double the full forced outage rate. The rule applied for the partial rate is therefore 2x the rule applied for the full rate.

The outage increase in Scenarios 1 and 2 will be applied as follows:

- For coal plants whose retirement has been delayed, and for which a formal agreement does not apply, the forced outage rate (full outage) is assumed to ramp up by 1% every year for the five years before its retirement year, leading to a 5% increase in the outage rate of its retirement year both in that year and the year prior. See the below table for an example of a coal plant retiring in 2030:

Table 3-2. Full outage rate assumptions

Scenario/year	2024	2025	2026	2027	2028	2029	2030
Base Case forced full outage rate	a%	b%	c%	d%	e%	f%	g%
Scenario 1 & 2 forced full outage rate	a%	g% + 1	g% + 2	g% + 3	g% + 4	g% + 5	g% + 5

[16] AEMO, Quarterly Energy Dynamics – Q4 2024.

- For coal plants whose retirement has been delayed, and for which a formal agreement does not apply, the forced outage rate (partial outage) is assumed to ramp up by 2% every year for the 5 years before its retirement year, leading to a 10% increase in the outage rate of its retirement year both in that year and the year prior. See the below table for an example of a coal plant retiring in 2030:

Table 3-3. Partial outage rate assumptions

Scenario/year	2024	2025	2026	2027	2028	2029	2030
Base Case forced partial outage rate	h%	i%	j%	k%	l%	m%	n%
Scenario 1 & 2 forced partial outage rate	h%	n% + 2	n% + 4	n% + 6	n% + 8	n% + 10	n% + 10

Coal random outage patterns

10 different outage patterns are assumed and applied in the modelling, that match the overall outage rates noted above.

3.2 Gas price settings

Under the scenarios in which less renewable capacity is built in the NEM, gas can be expected to play a greater role in supplying consumers with electricity than would otherwise be the case. Therefore, gas price assumptions play an important role in determining price outcomes, particularly in periods where coal generation is not available, and demand is high.

In this analysis, Jacobs uses the following gas price assumptions:

- Base Case – AEMO 2024 ISP Step Change gas price assumptions
- Scenarios 1 and 2 – AEMO 2024 ISP Step Change gas price assumptions plus $2/GJ price uplift.

Jacobs reviewed the latest Gas Statement of Opportunities (GSOO) 2024 and corresponding IASR 2023 and ISP 2024 reports which are summarised in Appendix B. The assumptions to derive the uplift in gas prices is described in the next section.

3.2.1 Additional gas supply price estimate

AEMO noted in GSOO 2024 that based on the current available gas supply, gas shortfalls are expected from 2025 onwards on extreme peak demand days. Considering gas demand for gas-powered generation (GPG) in the Step Change scenario, this reaches 63 PJ in 2030. Any gas demand for generation above these levels will likely see a more constrained gas market. For the modelling undertaken in this report, GPG requires 211 PJ of gas supply in scenario 1. This much higher gas consumption is driven by the reduction in renewable energy generation and the consequent greater reliance on gas fired stations to operate when coal and renewable capacity is insufficient to meet demand.

To price additional gas supply required for GPG, Jacobs has adopted the Australian Competition and Consumer Commission (ACCC) liquefied natural gas (LNG) netback price methodology[17], on an import basis (where currently this methodology is applied on an export basis), to account for this additional supply

[17] The LNG netback price is a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port. As such it represents the opportunity cost to gas suppliers of supplying into the domestic market, versus their alternative of supplying incremental volumes into the LNG export market. The ACCC utilises the Asian LNG spot prices and oil-linked LNG contract prices due to the significant role in influencing gas prices in the ECGM.

Source: Jacobs analysis of ACCC LNG netback price publications https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30/lng-netback-price-series required, assuming that marginal gas supply beyond the existing Step Change forecast in the 2024 ISP would need to be sourced through LNG import facilities, given forecast shortfalls and a tight supply demand balance in the timeframe.

Given that additional gas is required across Scenarios 1 and 2 to supply the market in 2030, the marginal supplier into the market in the timeframe is assumed to be an LNG importing facility, and as such there is a change in LNG parity in east coast gas markets to LNG import basis versus LNG export equivalent. Potential LNG import facilities include the proposed Port Kembla NSW (with an operational start date of 2026), the proposed Outer Harbour South Australia (with an operational start date of 2026) and the proposed Geelong Victoria (with an operational start date of 2027)[18].

In AEMO's GSOO 2024, it was specified that none of the LNG import terminals are considered committed or anticipated due to various infrastructure considerations. In this analysis, an import terminal at Port Kembla is assumed to provide the marginal supply of gas into the east coast gas market in 2030. This facility is currently under construction.

Below, Jacobs illustrates the impact of moving from LNG export to LNG import parity, using ACCC LNG netback methodology. [19] This approach converts the LNG spot price in Asian markets (derived off oil prices) into an equivalent price at Wallumbilla in Queensland in the export case, and at Port Kembla in NSW in the import case. The calculation allows for freight costs to and from the LNG market, pipeline costs to and from LNG export and regasification facilities, and ongoing transport across the east coast gas market. Assumptions are sourced from Acil Allen and ACCC.

Table 3-4. LNG import versus export parity

LNG Export netback			**LNG import netback**		
ACIL allen oil price	$ 65.00	USD/bbl	ACIL allen oil price	65	USD/bbl
Contract slope	0.14	%	Contract slope	0.14	%
LNG Spot price	$ 9.10	USD/mmbtu	LNG spot price	$ 9.10	USD/mmbtu
Freight	0.72	USD/mmbtu	Freight	0.72	USD/mmbtu
FX	0.70	USD/AUD	FX	0.70	USD/AUD
Gladstone FOB	**$ 11.42**	**AUD/GJ**	**Prior to regas**	**$ 13.38**	**AUD/GJ**
LNG plant efficiency	0.949187	%	Regas variable opex	0.1	USD/mmbtu
Variable pipeline costs	0.037967	AUD/GJ	Regas fees	0.14	AUD/GJ
Wallumbilla	**$ 10.80**	**AUD/GJ**	**Port Kembla Delivered**	**$ 13.52**	**AUD/GJ**

Source: Jacobs' analysis of gas prices import and export parity using data from Acil Allen for GSOO 2024 and ACCC information netback prices calculation

Using the same assumptions as adopted in the Acil Allen report for GSOO 2024, in which the Brent crude oil price is forecasted to average US$65/barrel in 2030, the LNG export netback price converts to $10.80/GJ at Wallumbilla.

For LNG import, the Port Kembla delivered equivalent is $13.50/GJ. The key difference between the export netback and the import netback is that LNG freight costs of USD 0.72/mmbtu[20] are added to the market price for LNG rather than subtracted.

This differential exceeds AUD$2/GJ at the point of delivery or export.

Based on the assumption of a single LNG regasification facility operating at Port Kembla, and the cost of delivering incremental gas supply volumes into accompanying markets in the east coast gas system using various networks (from Queensland to Melbourne, NSW, Brisbane and Adelaide), this resulted in a delta in gas

[18] All LNG import terminals are considered proposed by AEMO GSOO 2024, with only Port Kembla securing long-term contract for a floating storage regasification unit (FSRU) in 2021

[19] ACCC LNG netback price methodology: https://www.accc.gov.au/system/files/Guide%20to%20the%20LNG%20netback%20price%20series%20-%20September%202022.pdf

[20] USD 0.72/mmbtu represents the average of freight values from the ACCC LNG netback calculation from 2018 to the present day.

costs of $2.30/GJ on average between a market that obtains its marginal supply from LNG export parity supply versus LNG import parity supply to cater for the additional GPG supply required.

Based on this summary of the change in netback basis, a $2/GJ price uplift is applied under Scenarios 1 and 2 to represent the likely higher cost of gas in a market with significantly increased gas demand. This uplift is applied equally to all gas-fired generators in all states of the NEM.

3.3 Gas infrastructure

With reduced renewables build and a greater reliance on gas fired generation, there are also implications for the gas infrastructure in the east coast gas market in the timeframe.

The 2024 ISP outlines GPG capacity assumptions under the Step Change scenario. The gas technologies included are categorised into mid-merit gas and flexible. The former is categorised by Combined Cycle Gas Turbines (CCGT) being used for baseload support due to higher efficiency and longer start-up times, while the latter typically consists of Open Cycle Gas Turbines (OCGT) used primarily for peaking due to faster response times but lower efficiency.

Table 3-5 illustrates the total available gas capacity in 2030 under the 2024 ISP Step Change scenario.

Using the ISP capacity projections and heat rates for CCGT and OCGT for current and future gas assets[21], the technical peak load (TPL) has been calculated for different hours of operation per day. Table 3-6 shows peak gas load for stations in the NEM relative to the Gas Statement of Opportunities (GSOO) forecast winter peak demand for the Step Change scenario. The results indicate that the 2030 peak gas day demand would be met with approximately 8 hours per day of GPG operation.

Table 3-5. Mid-merit and flexible gas capacity, 2030, ISP Step Change scenario.

Gas type	Region	2030
Mid-Merit Gas	New South Wales	0.44
	Queensland	1.60
	Victoria	0.50
	South Australia	0.53
	Tasmania	0.00
	NEM - Total	3.07
Flexible Gas	New South Wales	2.67
	Queensland	2.17
	Victoria	1.90
	South Australia	1.63
	Tasmania	0.18
	NEM - Total	8.55
Total Gas Capacity		11.61

[21] Provided in the GHD 2018-19 AEMO Costs and Technical Parameter Review and Aurecon: 2022 Cost and Technical Parameters Review for current and future gas assets respectively.

Table 3-6. Inferred technical peak load at different hours of operation of CCGT and OCGT[22]

	4 Hours / Day	8 Hours / Day	12 Hours / Day	18 Hours / Day	24 Hours / Day	GSOO Winter Peak Demand
2030 TPL (TJ / Day)	495	989	1,484	2,226	2,968	953

The GSOO winter peak demand of 953 TJ/day in 2030 would indicate a winter peak with about 8 hours of operation. Under scenario 1 modelled in this report, this peak demand for gas in winter increases to 1,800 TJ/day. This additional requirement for peaking gas supply would potentially require additional costs on the part of gas operating stations in this timeframe.

3.4 Transmission impact analysis

As part of the electricity network delivering energy to customers, transmission networks transport high-voltage electricity from large-scale generators located away from population centres to large users and consumers located in major load centres. Transmission developments are capital intensive and are recovered from end users of electricity.

Changes in the pattern of renewable energy build and of thermal plant retirements have a bearing on transmission investments and the costs passed through to consumers over time. This means that building less renewable energy in Scenarios 1 and 2 could, in theory, reduce the need for additional transmission. This could in turn place downward pressure on retail bills, offsetting the upward pressure from more coal and gas generation in the mix.

Our analysis finds that this does not occur in the modelled period. This is because most of the transmission infrastructure planned for the period out to 2035 is already committed. That is, it is already locked in to proceed, mostly to address issues like congestion that are already impacting the grid. Put another way, these transmission projects are likely to proceed anyway, regardless of the volumes of renewables in the grid.

There are several variables to be considered when evaluating the impact of deferred renewable energy build on transmission capital expenditure, including:

- The timing of planned transmission investment, and hence which investments could or could not be deferred.
- The potential need for augmentation of transmission networks to accommodate more gas and other thermal generators.

These are discussed in turn below.

3.4.1 Timing of transmission-built cost savings

The AER is the economic regulator for a combined value of regulatory asset bases (RAB) of electricity networks currently valued at $116 billion, excluding Western Australia. The AER's latest *State of the Energy Market* report noted that 46% of the retail bill comprised of network costs.[23]

These costs going forward are impacted by future investment in the network to connect to new renewable energy. The change in renewable capacity build observed in the scenarios run in this report is significant. The

[22] Based on mid-merit and flexible load projections in the ISP, compared with GSOO winter peak demand forecasts in 2030 and 2035.

[23] The State of the Energy Market 2024, AER: https://www.aer.gov.au/system/files/2024-11/State%20of%20the%20energy%20market%202024.pdf

reduction in capacity built between Scenarios 1 and 2 and the Base Case amounts to 23.6 GW less grid-scale renewable energy by 2030.

The question therefore can be asked, how much might transmission build and therefore transmission costs be expected to fall within the modelled timeframe because of the assumed reduction in renewable build?

To date, many of the projects included in the 2024 ISP optimal development path are committed and anticipated. That is, they are well advanced in the process of development or construction, and therefore are unlikely to be impacted by changes in policy with regard to renewable energy build targets in the timeframe analysed in this report. These projects include:

- Far North Queensland Renewable Energy Zone (REZ) (in service June 2024).
- Project EnergyConnect (in service September 2024 stage 1 and May 2026 stage 2).
- Western Renewables Link (expected in service July 2027).
- Central West Orana REZ Network infrastructure Project (expected in service January 2028).
- Copper String 2032 (expected in service June 2029).

The timing of already actionable projects could also see many of these projects in construction in the next 2-3 years:

- Humelink (in service July-December 2026).
- Sydney Ring North (in service December 2028).
- Victoria to NSW Interconnector (VNI) West (in service December 2028).

In relation to transmission developments for renewable energy zones, some of the development required prior to 2030 is needed to relieve congestion and to accommodate projects already in advanced stages of development. In New South Wales, for example, the Central West Orana and New England REZs have projected renewable generation of 8 GW and 6 GW by 2030-2031 respectively.

Transmission developments that might be avoided or deferred would for the most part comprise of investments that would see commissioning after 2030.

3.4.2 Thermal generation network requirements

Assuming renewable build is significantly lower as per the assumptions in Scenario 1 and 2, new infrastructure may be required for new gas-fired generating stations in the NEM, where the existing stations are insufficient to provide the NEM's energy needs. Some of these GPG projects may have more flexibility in terms of their location, compared to renewable energy projects, and may therefore avoid the need for additional transmission build to allow them to connect. However, many GPGs will still significant locational constraints, particularly those related to the availability of fuel production, transportation and storage facilities.

This means that only some of these new GPG projects will necessarily be able to locate close to existing transmission infrastructure. Some additional transmission infrastructure build could therefore be required for many new GPGs, in a scenario with additional fired generating capacity.

In looking at the customer bill impact of transmission and distribution costs under the ISP Step Change scenario, the AEMC modelled wholesale, transmission and distribution and network costs in its recent *2024 Residential Electricity Price Trends* report. The AEMC used the AEMO ISP as the driving assumption of the renewables and transmission build-out to forecast retail prices. This analysis showed that network prices, inclusive of transmission and distribution costs, were projected to fall slightly over the 10-year outlook of that forecast out to FY2034. The AEMC noted that a 23% increase in residential consumption over the timeframe offsets increases in both transmission and distribution investment needed to accommodate new generation.

3.5 Value of emissions reductions

The value of emissions reductions are taken from May 2024 AER guidance as shown below.

Figure 3-3. AER value of emissions reductions

Year	Average IPCC & ACCU (using official IPCC) AUD2023	Year	Average IPCC & ACCU (using official IPCC) AUD2023
2023	66	2037	181
2024	70	2038	194
2025	75	2039	207
2026	80	2040	221
2027	84	2041	236
2028	89	2042	252
2029	95	2043	268
2030	105	2044	286
2031	114	2045	305
2032	124	2046	325
2033	135	2047	346
2034	146	2048	369
2035	157	2049	393
2036	169	2050	420

Source: AER Valuing emissions reduction, May 2024[24]

3.6 Capital cost assumptions

Jacobs used published sources of capital cost estimates from AEMO and the Commonwealth Scientific and Industrial Research Organisation's (CSIRO) GenCost report to summarise renewable costs for onshore wind, offshore wind, utility scale solar, utility scale batteries as compared to the capital cost for new CCGT and OCGT gas generators. Renewable capital expenditure (capex) is expected to go down over time as the technologies continue to develop. CCGT and OCGT capex is expected to remain relatively unchanged over time, given the maturity of the technologies.

Jacobs also considered the cost of capital (i.e. financing cost) expressed as weighted average cost of capital (WACC) from equity and debt financing for the different technologies. WACC for thermal technologies is expected to increase over time due to the increased carbon risk over time and the risk of asset stranding.

The costs of hydrogen ready OCGT is also illustrated as an alternative to new build gas generation. Specifically, the Snowy Hydro hydrogen capable dual fuel gas peaking plant recently constructed at Kurri Kurri in the Hunter Valley is used to establish the cost premium between this and the standard OCGT cost assumptions in AEMO's IASR 2023 report.

3.6.1 Inputs

As inputs to the capital cost analysis, we use AEMO's assumptions on new builds as published in the 2024 ISP Inputs and Assumptions Workbook, which was released in July 2024, for the Step Change scenario.

[24] https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf

Capex

The costs are in $/kW, real 2023 basis unless otherwise stated. Tables below show capex costs assumptions of various technologies in 2030. Except for hydrogen ready gas turbines, all costs are based on AEMO 2024 ISP.

Table 3-7. Capex cost assumptions in 2030

Technology (2030)	Victoria			State Range	
	Capex	Connection cost	Total capex	Min	Max
PV	1,215	269	1,484	1,402	1,639
Wind	2,130	277	2,407	2,336	2,575
OSW fixed	4,766	342	5,108	5,107	5,220
OSW floating	5,706	342	6,048	6,047	6,160
Biomass	8,211	115	8,327	8,297	8,327
OCGT small	1,525	115	1,640	1,610	1,640
OCGT large	922	115	1,038	1,008	1,038
CCGT	1,810	80	1,891	1,891	1,926
CCGT with CCS	4,587	80	4,667	4,667	4,703
H2 engine	2,242	115	2,358	2,328	2,358
H2 ready GT	1,300	115	1,415	1,386	1,415

Source: AEMO 2024 ISP, Jacobs analysis

The 2030 cost of hydrogen ready gas turbine is based on the reported cost of Kurri Kurri gas fired power plant that is designed to be hydrogen ready. The plant is reported to cost $950 million with capacity of up to 750 MW with commentary estimating that the cost could increase to $1.5 billion. This translates to a cost of 1,267-2000 $/kW.

FOM, VOM, Heat rate

The table below shows assumptions on FOM, VOM, Heat rate of various technologies. Assumptions for these cost components are the same for all states and the same for 2030 in real terms. Assumptions for H2 ready GTs is assumed to be similar to those adopted for large scale GTs.

Table 3-8. FOM, VOM, Heat rate

Technology	FOM ($/kW/annum)	VOM ($/MWh)	Heat rate (GJ/MWh HHV s.o.)
PV	18.72	-	-
Wind	27.53	-	-
OSW fixed	169.73	-	-
OSW floating	625.63	-	-
Biomass	161.48	10.33	17.37
OCGT small	13.47	12.83	10.19
OCGT large	10.91	7.81	10.93
CCGT	11.66	3.96	7.25

CCGT with CCS	17.48	7.70	8.96
H2 engine	35.29	-	11.70
H2 ready GT	10.91	7.81	10.93

Source: AEMO 2024 ISP, Jacobs' analysis

Fuel cost

The costs are in $/GJ, real 2023 basis unless otherwise stated. The table below shows fuel cost assumptions for various technologies in 2030.

Table 3-9. Fuel cost assumptions for various generating unit types in FY 2030, $/GJ

Technology	Victoria	State Range	
		Min	Max
Biomass	0.62	0.62	0.62
OCGT small	11.41	11.41	12.44
OCGT large	11.41	11.41	12.44
CCGT	9.31	9.31	10.15
CCGT with CCS	9.31	9.31	10.15
H2 ready GT	11.41	11.41	12.44

Source: AEMO 2024 ISP, Jacobs' analysis

WACC

The WACC is assumed to be 7% based on the AEMO 2024 ISP Step Change scenario for all technologies.

Capacity factor

The capacity factor of renewable technologies is based on the average capacity factor of reference years of select REZs published in the 2024 ISP, as shown in Table 3-10 below. Thermal plants exhibit a capacity factor ranging from 30-60%.

Table 3-10. Capacity factors

Technology	Capacity factor (%)	Traces reference
PV	27%	V2 Murray River
Wind	36%	V3 Wind Medium Western Victoria
OSW fixed	47%	V7 Gippsland Coast
OSW floating	49%	V7 Gippsland Coast
Biomass	60%	
OCGT small	30%	
OCGT large	30%	
CCGT	60%	
CCGT with CCS	60%	
H2 engine	30%	
H2 ready GT	30%	

Source: AEMO 2024 ISP, Jacobs' analysis

3.6.2 LCOE analysis

The levelized cost of energy (LCOE) analysis is a method used to evaluate and compare the average cost of electricity generation over the lifetime of different energy projects. It calculates the average net present cost of electricity generation for a power plant, considering all associated costs that are incurred throughout its operational life. LCOE figures in this section are based on costs in Victoria, unless otherwise stated. LCOEs for other states follow similar patterns.

Figure 3-4 below shows the LCOE of various technologies in Victoria. Solar PV and onshore wind have the lowest LCOE of all technologies evaluated. In 2030, CCGT, the cheapest of all fossil-powered technologies, is 40% more expensive than onshore wind, while H2-ready GT is more than double the cost of onshore wind.

In 2030, H2 ready GTs are assumed to be fuelled by gas but later will eventually shift to hydrogen.

Figure 3-4. LCOE of various generating technologies in Victoria

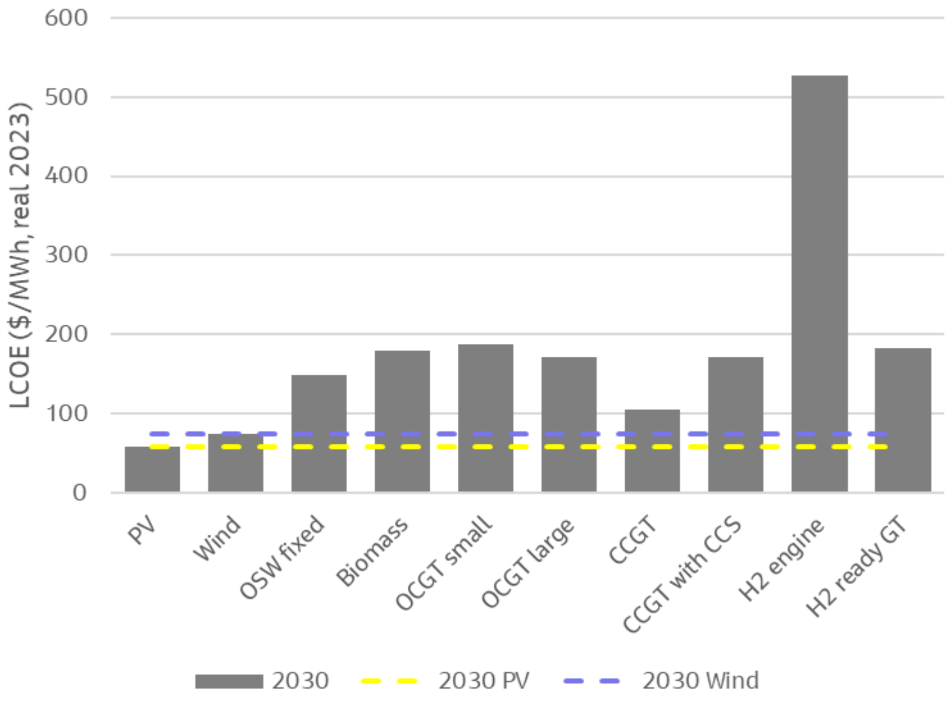
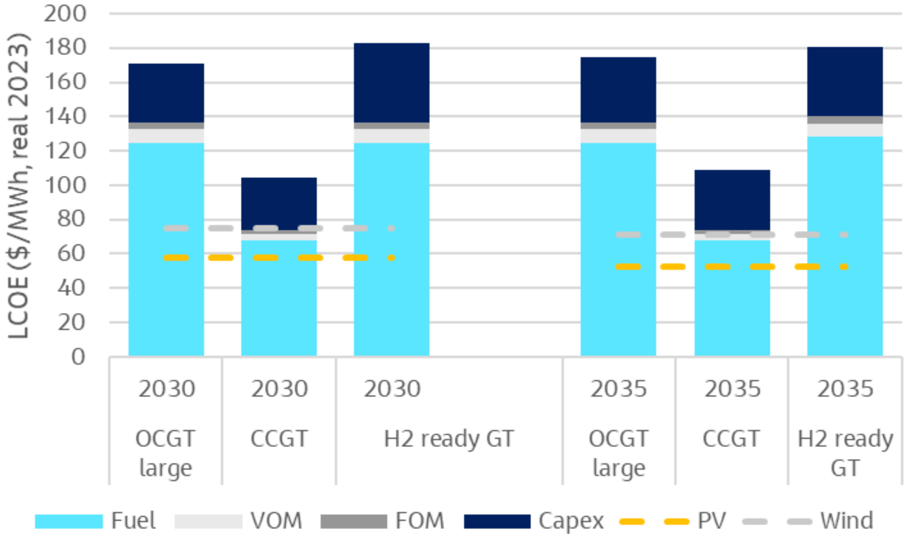


Figure 3-5 below shows the LCOE of gas-based generation technologies broken down into their main cost components. Fuel costs make up most of the cost: about 71-73% of the LCOE for OCGT and 62-65% for CCGT can be attributed to fuel costs. The rest of the cost is made up of capex, and operations and maintenance costs. While it is significantly more expensive to build H2-ready OCGTs compared to large OCGTs, the difference in their LCOEs is relatively small (H2-ready is 7% higher than large GT in 2030). This is because fuel costs, which are the same for both technologies in 2030, form a large proportion of the LCOE.

Figure 3-5. LCOE of various gas-fired generating technologies in Victoria



4. Results

4.1 Wholesale spot market outcomes

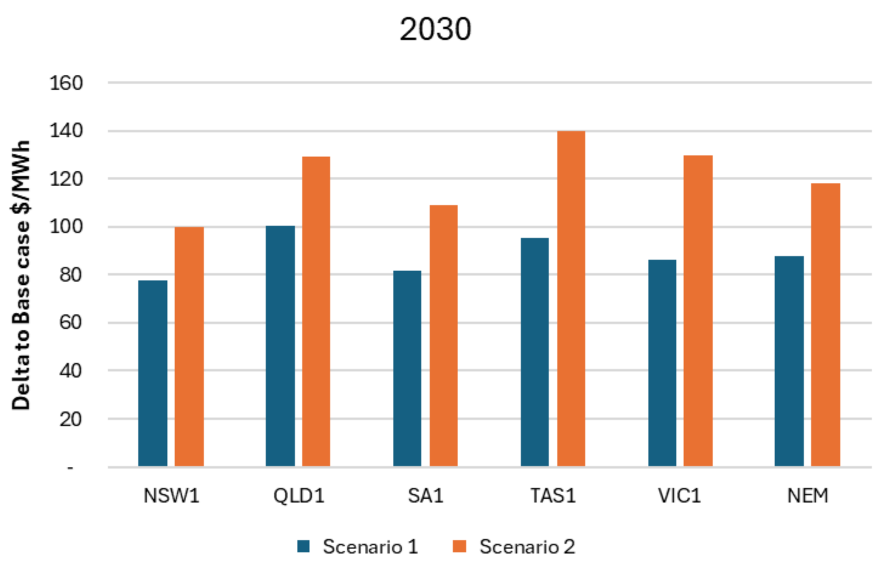
The focus of our analysis has been on the wholesale price impacts associated with reducing utility scale renewable build to 2030. The wholesale component of retail bills is the main bill component affected over the timeframes explored in this analysis.

Jacobs' analysis of wholesale price changes between the Base Case and Scenarios 1 and 2, shows increases in wholesale spot prices in Scenarios 1 and 2 versus the Base Case. This is driven by the greater role for aging thermal coal plants and gas generation in providing the balance of energy to the market that is removed through the reduced renewables build. Coal and gas play a much greater role in these scenarios in providing energy and peaking supply capacity to the market than they do in the Base Case.

In Scenario 1 across the 100 scenarios analysed, wholesale energy prices increase by $88/MWh on average in 2030. In Scenario 2, they increase by $118/MWh in 2030.

This price uplift occurs on average (i.e. across the mean price outcome in all scenarios). Figure 4-1 below illustrates the wholesale spot price changes in more detail.

Figure 4-1. Average wholesale market price differentials



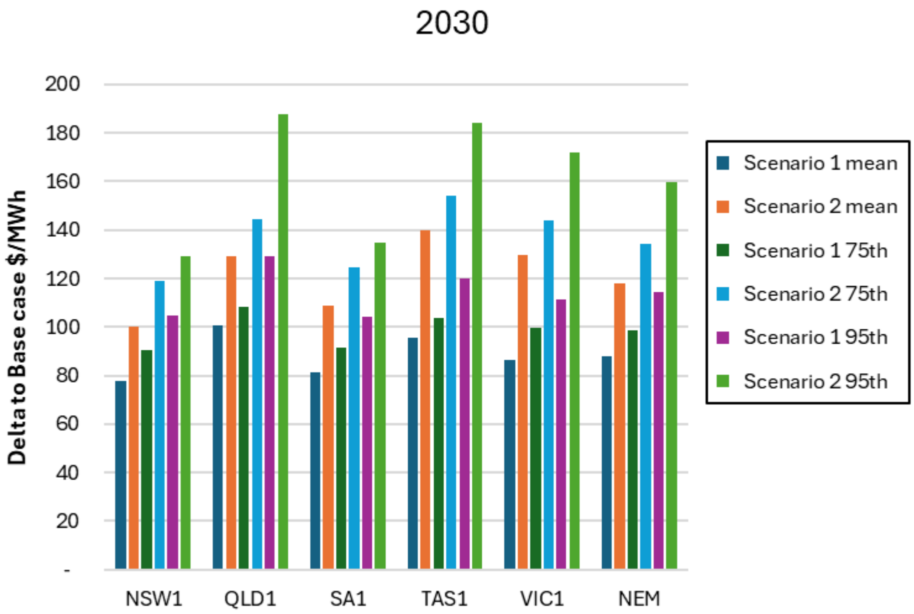
Note: $ impacts by state are impacted by different consumption levels. Tasmania for example has higher representative consumption patterns than other states.

Outcomes under more difficult conditions

The development of 100 price paths based on differing assumptions in relation to weather, demand and generator outages allows us to analyse price differences also at the 75th percentile[25] and the 95th percentile of outcomes. These help to illustrate price differences under more challenging conditions. Forecasts of retailer costs prepared by the AEMC for residential price trends and by the AER for the Default Market Offer (DMO) have drawn on wholesale price outcomes at the 75th percentile and 95th percentile in determining retailer wholesale costs.

[25] 75th percentile here denotes the 75th highest price difference between scenario 1 and the base case.

Figure 4-2. Wholesale price outcomes at mean, 75th and 95th percentiles



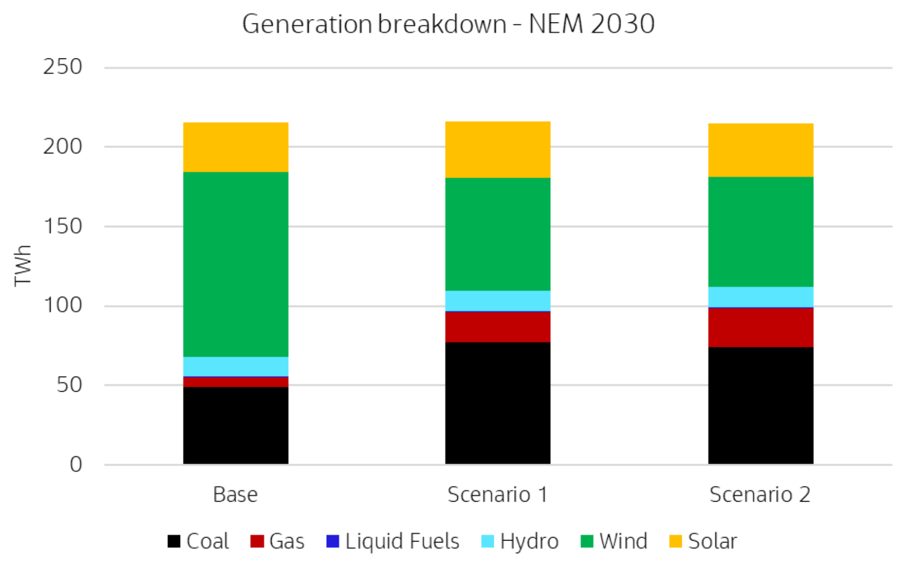
Analysis of the 75th and 95th percentile price deltas in scenario 1 would see potential spot price increases of $99-114/MWh.

Analysis of the 75th and 95th percentile of price deltas in scenario 2 would see potential price increases of $135-160/MWh.

4.1.1 Observed trends in wholesale spot price

In total, across the NEM for a sample run in 2030 the reduction in renewable generation particularly wind is replaced by a combination of gas generation and aging coal generation. Figure 4-3 below indicates that approximately 20% of total NEM demand in Scenario 1 and Scenario 2 require such replacement.

Figure 4-3. NEM generation breakdown for 2030 TWh

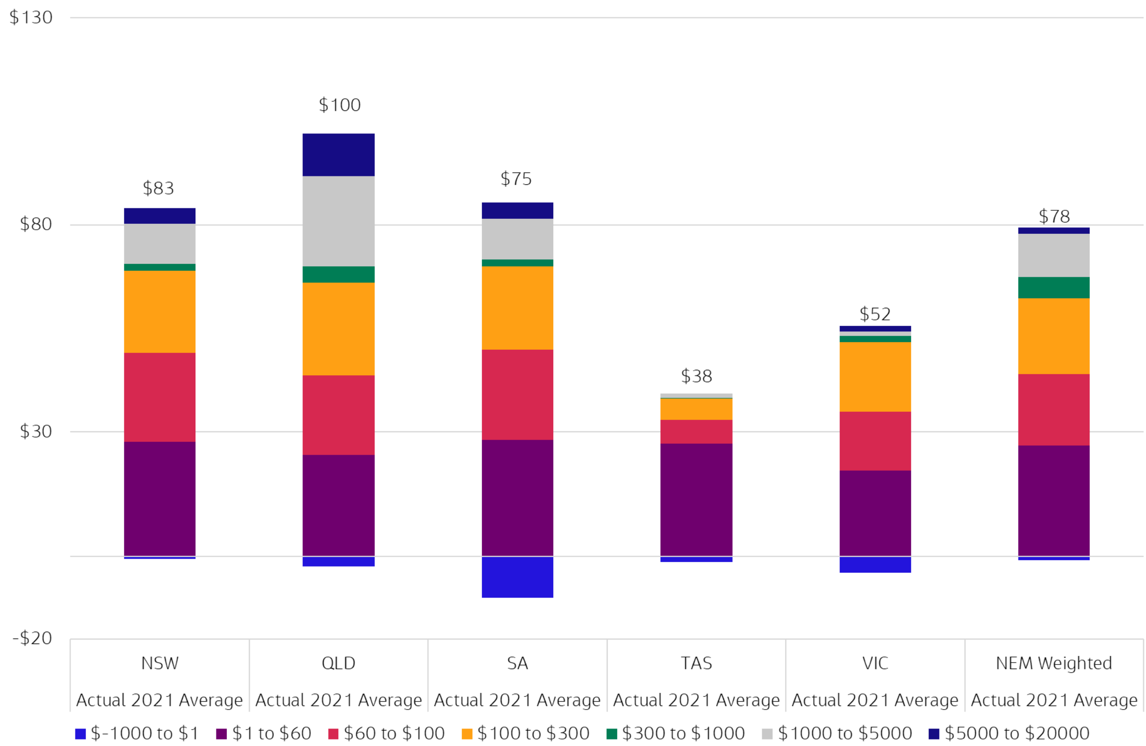


Source: Jacobs analysis

The NEM wholesale price in each state is determined by the marginal generation providing the last unit of energy. Looking at the event in 2021 when the Callide Power Station C4 unit was out due to fire, the state of Queensland experienced its worst power outages in more than a decade[26].

The ramifications of power outages in Queensland were felt in other parts of the NEM, where it was observed that more expensive generation sources were providing the balance of energy required as the Callide Power Station was out of service.

Figure 4-4. Actual 2021 wholesale spot price outcomes by State & NEM weighted average breakdown by price bands, Real 2024 $



Source: Jacobs analysis of AEMO NEM data 2025

One way to understand the breakdown of generation supporting the NEM in such catastrophic event is to analyse the contribution of price bands to the total wholesale spot price stack in each state. The price bands provide insights as to which generators were marginal for most of the time for the year.

For 2021, the following observations can be made by analysing the price bands contribution to the total wholesale spot price in each state for 2021:

- In Queensland, grey and dark blue vertical bars at the top of prices above $1,000/MWh indicated that the marginal plant contributing to the total price was potentially the reserved capacity[27] across the mix of coal, gas and hydro plants. There is also evidence that wholesale spot prices were reaching the market price cap more often than other states in the NEM.

[26] Callide Power Station outage: https://www.abc.net.au/news/2025-02-04/callide-power-station-fined/104895370

[27] Reserve capacities in power system studies relate to backup generation capacity that is usually used by the electric grid in the occurrence of unexpected fault such as the unavailability of a power plant. These sources are the most expensive as they act as reliability or scarcity value high enough to induce generation and demand to match nearly all the time (Reference AEMC, assessed 25th February 2025): https://www.aemc.gov.au/news-centre/perspectives/economists-corner-profiling-capacity-market-debate)

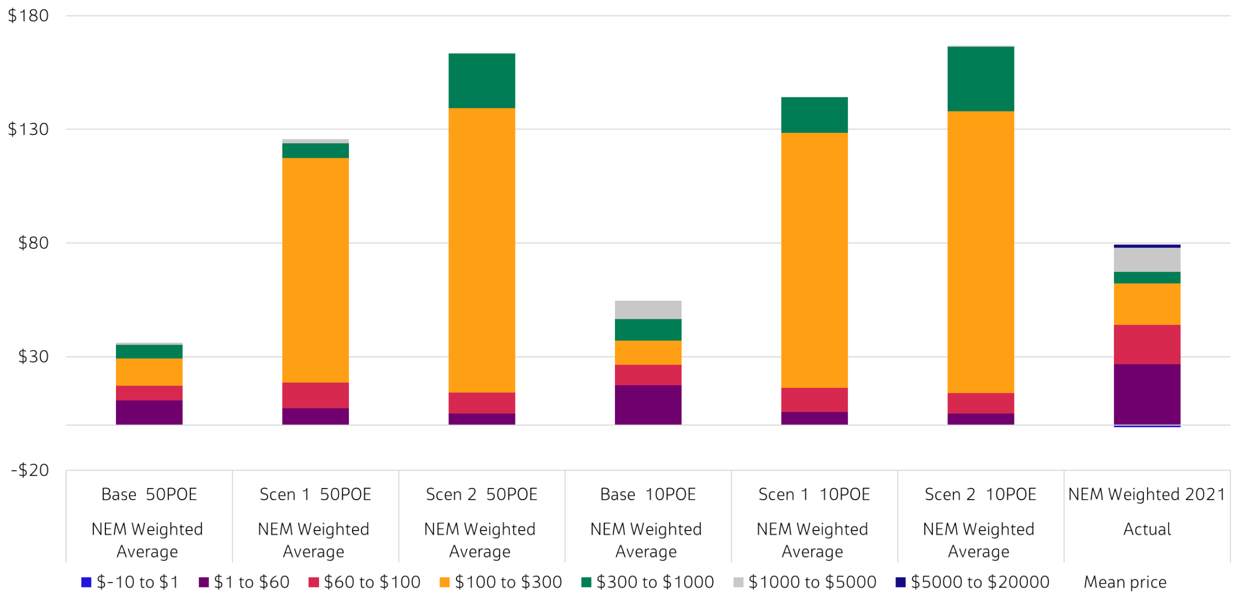
- In SA, the higher level of renewable generation penetration helped in this instance in reducing the average wholesale spot price outcome as represented by the contribution of the price bands less than $1/MWh (lighter blue, plotting below $0/MWh on the x-axis).

In the modelled scenarios for 2030, the Base Case with POE50 demand sees the lowest wholesale spot price outcomes compared to Scenario 1 and Scenario 2. Renewable generation in Base Case POE50 is marginal for a greater amount of the year, but this is replaced by a combination of coal and gas generation in Scenario 1 and Scenario 2.

The observations in Figure 4-5 of **one sample run** below is indicative of the outcomes of extending the life of aging coal plants in the NEM in scenarios 1 and 2:

- In the Base Case with POE50 demand, the low price is a result of renewable energy with marginal cost of near $0/MWh setting the price a greater proportion of the time. The vertical bars between $1/MWh and $300/MWh indicate that during periods of low renewable energy to meet demand, generation such as coal and gas is supporting the balance of the energy required in the NEM.
- Under higher demand such as POE10 demand, the NEM is supported by reserved capacity from either coal, gas, hydro or potentially demand side participant (DSP). This is observed in the presence of grey vertical bars of $1,000/MWh to $5,000/MWh for the POE10 sample.
- In contrast to the Base Case, in Scenario 1, as less renewable generation is available to the NEM the demand is balanced by coal and gas generation. The increase in orange vertical bars indicates that gas is the marginal or clearing generator more often than Base Case, i.e. it sets the market price more often.
- This effect is further compounded by coal generators more frequent outage periods, where again gas Is called on to supply the market and more likely to be the generator setting the market price. The contribution from green vertical bands, representing prices between $300/MWh to $1,000/MWh is indicating that other forms of generation such as liquid fuel is also supporting the demand balance resulting in higher wholesale spot price outcome.
- Scenario 2 further confirms the observations in Scenario 1, that when catastrophic events occur, NEM demand is more likely to be met with higher gas generation.

Figure 4-5. 2030 sample run wholesale spot price outcome by State and NEM weighted average breakdown by price bands, Real 2024 $



Source: Jacobs analysis of AEMO NEM data 2025

Comparing the outcome of these scenarios to actuals from 2021, in 2021 the NEM demand was met with greater contributions from plants or generators that are marginal below the $100/MWh price bands which is mainly renewable generation and coal generation.

As we move towards 2030, in the Base case less coal generation is marginal due to expected exits, and renewable generation is expected to set the price more of the time. Keeping coal generators online for longer and delaying renewable generation capacity build in the NEM is likely to significantly increase the extent to which gas generators are marginal, or set the price in the NEM, and therefore will drive wholesale spot price outcomes higher than ISP 2024 Step Change Scenario.

4.2 Retail bill impacts

Jacobs translate wholesale spot price changes in $/MWh to c/kWh impacts on retail bills. A $10/MWh wholesale price impact is assumed to have a 1 ckwh retail bill impact. Jacobs make no other changes to other parts of the bill and use the change in wholesale spot prices as an indication of the change in the cost of wholesale energy in retail bills. Other components of the bill, not modelled here, include network costs, environmental scheme costs and retail costs.

The changes in wholesale costs are compared to total bill costs in ckwh for the financial year 2030 for each region of the NEM provided in the AEMC's 2024 residential electricity price trends report.[28] The AEMC conducted this analysis of total bill costs in the NEM using AEMO's ISP Step change scenario as its basis. Jacobs base case price paths, i.e. the 100 price paths reflecting the build pattern under the ISP Step change scenario, broadly capture wholesale costs published in the AEMC report for the financial year 2030. Price impacts in this analysis in % terms are therefore a % difference to the AEMC's 2030 figures.

The impact of the wholesale price changes seen in Figure 4-1 on the final retail bill in 2030 is significant.

Under Scenario 1, residential electricity bills are likely to increase by 30% on average across all states in the NEM in 2030 because of the impacts on the wholesale market. This would amount to an increase of $449 per annum for a representative consumer across NEM regions. This impact varies from state to state.

Under scenario 2 where a large coal fired generator is removed from operation the impact of slower renewable build increases to 41% on average or $606 per annum for representative consumers across NEM regions.

Table 4-1. Retail bill impacts for NEM residential consumers, 2030, $ per customer per annum

Region	Scenario 1	Scenario 2	Scenario 1 %	Scenario 2 %
New South Wales	$339	$436	23.6%	30.3%
Queensland	$568	$729	37.2%	47.8%
South Australia	$407	$544	20.9%	27.9%
Tasmania	$731	$1,074	39.7%	58.4%
Victoria	$408	$614	31.9%	48.1%
NEM[29]	**$449**	**$606**	**30.3%**	**41.0%**

[28] AEMC, Residential Electricity Price Trends, 2024. https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024

[29] Demand weighted by NEM region, AER demand figures for 2023-24

Note: Percentage change when compared to AEMC price trends figures for 2030 in each state.

A representative small business customer (with an annual usage of 10,000kWh[30]) is likely to experience a $877 increase in their bills under scenario 1 and a $1,182 increase in their bill under scenario 2 across the NEM.

Table 4-2. Retail bill impacts for NEM small business customers, $ per customer annum, 2030

Region	Scenario 1	Scenario 2
New South Wales	$778	$1,000
Queensland	$1,006	$1,290
South Australia	$815	$1,088
Tasmania	$954	$1,401
Victoria	$862	$1,298
NEM	$877	$1,182

Retail bill outcomes under more difficult conditions

Were the wholesale spot price impacts from the 75th and 95th percentile price projections highlighted in Figure 4-2 to flow through to retailer contracting costs, the potential impact on consumer bills would see bills rise between $503-$584 per household in scenario 1, and between $688-$824 per household in scenario 2 (shown below in Table 4-3).

Table 4-3. Retail bill impacts under more difficult conditions

Region	Scenario 1 (75th)	Scenario 1 (95th)	Scenario 2 (75th)	Scenario 2 (95th)
New South Wales	$394	$457	$520	$565
Queensland	$613	$729	$815	$1,062
South Australia	$457	$521	$622	$673
Tasmania	$795	$919	$1,182	$1,411
Victoria	$471	$526	$680	$813
NEM	$503	$584	$688	$824

Note: 75th denotes 75th percentile price, 95th denotes 95th percentile price.

4.3 Emissions impacts

In the ISP, AEMO forecast emissions of 39.5 Mt CO_2e in 2030. In the scenario 1 modelled outcome, emissions increase to 77.2 Mt CO_2e. This is an increase of 37.7 Mt CO_2e.

[30] The annual usage of a representative small business customer is taken to be 10,000 kWh, in alignment with the representative annual usage used in the calculation of the Default Market Offer (DMO) 6.

As noted in section 3.5, values can be attributed to emissions and emissions reductions. In this case the AERs value of emissions reductions is $105 in 2030, as such the value of these increased emissions under this assumption would be $3.9 billion.

The cost of fuel in the form of both coal and gas purchased to supply the NEM with electricity increases significantly in scenario 1 versus the base case. Gas costs increase from $770 million to $2.3 billion and coal costs increase from $1.1 billion to $1.8 billion, with renewable energy replaced with thermal sources.

5. Conclusions

5.1 Summary

The reduction in renewable generation capacity over the next five years and the replacement of that capacity with coal and gas generation drives higher cost outcomes for consumers.

The dispatch cost, or cost in real time of dispatch of renewables such as wind and solar is very low while for coal and gas it is higher driven by the cost of fuel to supply these stations.

In addition to the impact on energy costs, there is also an impact on price, through the bidding dynamics in the market. With less renewables, and less batteries in the system, large coal and gas generators play a greater role in setting market prices in each trading interval for the NEM. The impact of this is observed in the Scenario 1 results which see an average delta with the Base Case of $88/MWh, driving bill increases of 30% or $449 per representative household. In scenarios with large coal fired stations failing and higher demand scenarios, this delta can be higher, driving higher price outcomes for consumers.

The declining reliability of ageing coal generators plays a part in these high prices. Coal stations towards the end of their technical life are less reliable and subject to more unplanned outages than newer replacement technologies. If these units fail, they remove supply from the market at short notice, putting upward pressure on wholesale prices.

Gas prices also play a role in driving increases in consumer electricity prices seen in Scenarios 1 and 2. The east coast gas market, as has been indicated by AEMO in their Gas Statement of Opportunities reports, will likely see gas shortfalls in the latter part of the current decade if additional sources of gas are not identified and contracted for supply to the market. In a scenario with the much greater operation of gas-fired plant, and potentially the need for new gas-fired plants to be built, the supply demand balance for gas on the east coast is likely to be even further constrained. This is shown in scenario 1, where the modelled outcomes sees 211 PJ of gas consumed in 2030, a material increase on ISP figures of 63 PJ.

The likely solution to this, in the form of LNG regasification terminals, is likely to drive different price dynamics in the east coast market. Currently, the ACCC calculates the LNG netback off export parity pricing, that is, as if the marginal supply of gas into the east coast comes from an LNG producer switching supply from LNG export to domestic supply. In a market that imports increasing quantities of gas, this dynamic will likely shift to import parity, where prices are still tied to international markets, but with the additional cost of freight from that market. This is likely lead to higher gas prices with further implications for power prices in turn.

The Scenario 2 outcomes show wholesale price differences of $118/MWh on average across all states, driving increases in retail bills of 41% or $606 per representative household. The differential observed in this scenario is greater than that seen in Scenario 1, as a large coal fired plant is assumed to fail for the full duration of the modelled financial year. This result serves to identify the impact of relying to a greater extent on ageing coal-fired power to supply the system with energy in the medium-term, when some of these plants are close to the end of their technical life. The impacts of lower coal reliability and large plant failures have been observed in the recent history of the NEM, with the failure of the Callide C plant in Queensland, and the impact of the international gas market issues in 2022 on a NEM with a greater need for gas in that timeframe, because of reduced coal availability.

Under more difficult wholesale market conditions, the wholesale price differences may be greater with a consequent impact on consumer bills. In scenario 1 with lower renewables build the bill impact may increase to $503-$584 per consumer at the 75th to 95th percentile price outcomes. In scenario 2 the bill impact may increase to $688-$824 per customer at the 75th to 95th percentile price outcomes.

The snapshot analysis with 100 price paths covering different demand scenarios, different renewable output scenarios and different plant outage combinations helps to provide greater confidence that, under the assumptions used, power prices are likely to be materially higher for consumers between 2025 and 2030, if the build out of renewable generation is constrained to the extent set out in Scenarios 1 and 2, as compared to the base case.

5.2 Risks and Limitations

Any forecast of prices in the NEM is a representation of the set of assumptions used in the compilation of that forecast. Changes in relation to electricity demand, coal retirement dates, oil and gas prices, the installation of consumer energy resources by households, all have a significant bearing on these results.

The Eraring and Yallourn coal fired power stations are assumed in this analysis to retire as per agreed closure timetables between the owners of the stations and government. Were these two coal stations to operate beyond their current agreed retirement dates, this would have a bearing on the results.

Higher prices in scenarios 1 and 2 might ordinarily mean investment in new gas fired generation capacity is brought forward, i.e. it might occur earlier, either in 2030 or soon after. However, given the scenario involves nuclear plant entering the NEM later in the 2030s, prospective investors in this gas plant would have to consider the impact of this nuclear capacity soon after the installation of their own plant. Additional new gas plant capacity is also unlikely to reduce the prices observed in scenarios 1 and 2 to any significant degree, given the new plant would be subject to high gas costs and the recovery of capital expenditure.

The snapshot analysis approach, with 100 price paths, examining two scenarios under several different operating assumptions for the NEM, helps to address these limitations to some extent. The exchange of low-cost renewable energy resources for high-cost coal and gas resources has a significant impact on the cost of energy, the price of energy established through the settlement of the market, and the volume of emissions associated with the delivery of that energy.

Some allowance should be made in considering the results in this report for the extent of government support to generation, both renewable energy, dispatchable power and ageing coal fired power stations under different scenarios. In the Base Case, more renewable capacity is built and wholesale prices are lower. This may mean greater support payments by Government to renewable energy generators under existing schemes, including the CIS. However, this is limited to generators subject to those schemes, and for the duration of the support agreements.

In the counterfactual, Scenarios 1 and 2, prices are higher and so government support payments would be expected to be lower. However, ageing coal plants are extended in these scenarios, and this may involve direct government support in some instances.

Appendix A. Residential Electricity Power Bills

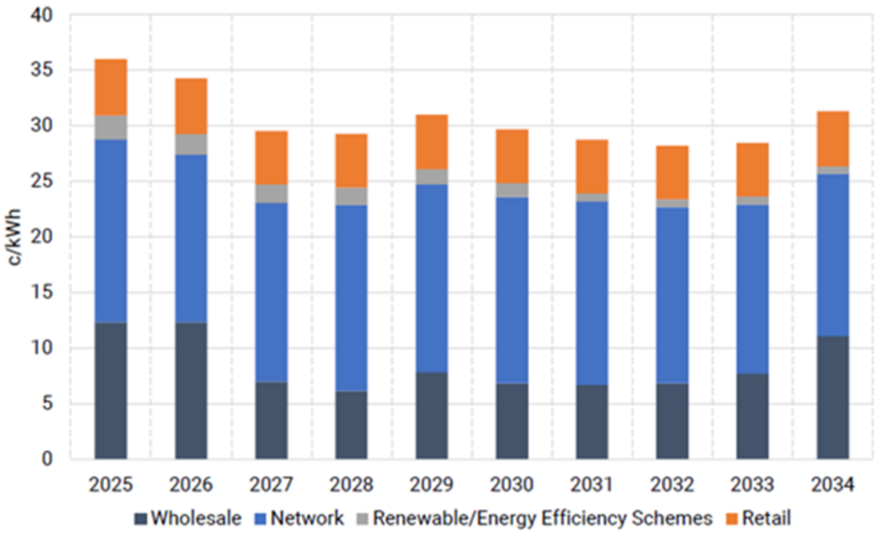
A.1 Overview

Residential consumers of electricity pay a power bill that includes all elements of the costs of delivering electricity, including the wholesale cost of producing electricity, the cost of accessing transmission and distribution networks to transport electricity to the consumer, the cost of retail operations, and the cost of environmental schemes, that subsidise investment in renewable generation and are recovered from consumers.

The residential electricity bill can be broken down into the following components:

- Wholesale costs, covering the cost of purchasing wholesale electricity and costs associated with market participation including network losses, ancillary and market fees.
- Network costs, covering transmission and distribution transport costs involved in delivering electricity to the end-user, as well as the cost of metering.
- Environmental costs, covering renewable and energy efficiency scheme costs associated with Commonwealth and state-based programs, that are recovered directly from electricity retailers.
- retail costs, covering the retailers' costs of providing service to the end-user, as well as the retail margin.

Figure A-1. Average Residential Electricity Price Outlook. Real Prices $FY25.



Source: AEMC, 2024 Residential Electricity Price Trends, 28 November 2024, p. 12

Figure A-1 summarises the outcome of the recent analysis conducted by the AEMC to forecast the total customer bill, based on assumptions from the 2024 ISP Step Change scenario. It depicts the average residential electricity price outlook for customers in the NEM over a 10-year horizon and was published by the AEMC as part of their 2024 Residential Electricity Price Trends report.

Over the forecast period, the AEMC finds that wholesale costs constitute approximately 30 - 40%, network costs 40 - 55%, renewable/energy efficiency schemes <5%, and retail costs 15 – 20% of the residential bill respectively. Of the costs, wholesale costs are among the most volatile and are particularly responsive to changes in the supply-demand balance, the balance of generation technology, and the type of technology built over time. Movement in wholesale costs is seen in the AEMC's analysis as a key driver of year-on-year changes in the residential bill.

The structure of each of the four main cost components underlying the retail bill is detailed further in the following sections.

A.2 Wholesale costs

Wholesale costs constitute energy purchased on the spot market, the cost of hedging contracts, and other wholesale costs including network losses, ancillary services and market fees.

A.2.1 Spot market

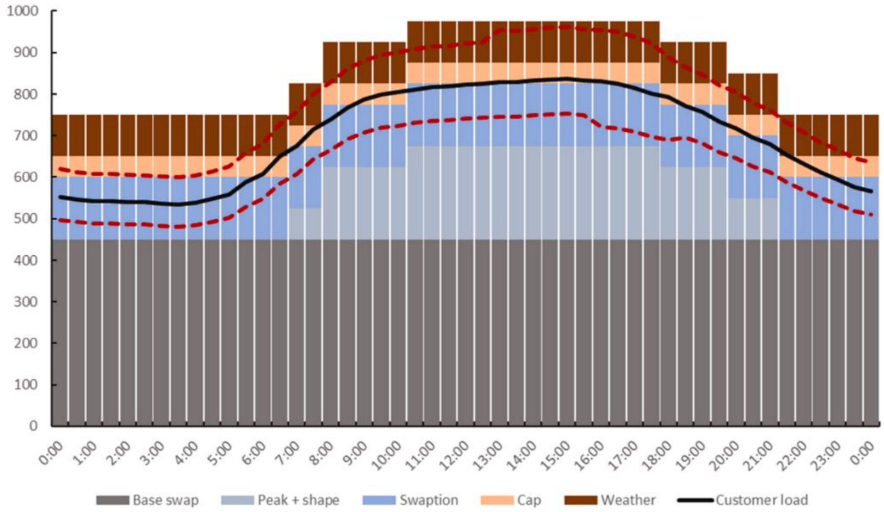
Retailers purchase electricity in wholesale markets with which to supply their customers. The AEMO dispatches the spot market every five minutes, using a constrained linear programming algorithm to match supply with demand in the NEM. Price volatility is a key feature of the spot market, driven by changes in supply and demand and the bidding behaviours of market participants. Wholesale spot market costs make up about 80% of total wholesale costs.[31]

A.2.2 Contract markets and hedging

To safeguard against price risk faced in the spot market, retailers trade in hedging contracts, in the form of exchange-traded (for example, on the ASX), or over-the-counter derivatives. Retailers may also be vertically integrated entities with their own generation assets that help them to manage risk. In many cases, a combination of exchange-traded, over-the-counter derivatives and utility owned generation assets will be used in the hedging portfolio of a retailer.

A prudent retailer will implement a contracting strategy to ensure it can meet the forecasted load of its customers at a particular price, without being overly exposed to changes in spot prices during the period in which electricity is delivered to the end user. This entails building up a portfolio of contracts in the period leading up to the time of delivery. Base swaps[32] and options are used to cover the bulk of predicted load, with caps used to manage more exceptional demand events. Peak swaps may also be used to manage price risk.

Figure A-2. Simplified view of a retailer's typical hedging strategy



Source: Flottmann, et. al., Derivatives and Hedging Practices in the Australian National Energy Market, June 2024

[31] AEMC, 2024 Residential Electricity Price Trends Methodology Paper, 28 November 2024, p. 3

[32] Base swaps allow for the supply of energy at a fixed cost rather than the changing spot price.

Financial contracts trade at a premium to wholesale spot prices. Contract market costs make up around 15% of total wholesale costs.[33]

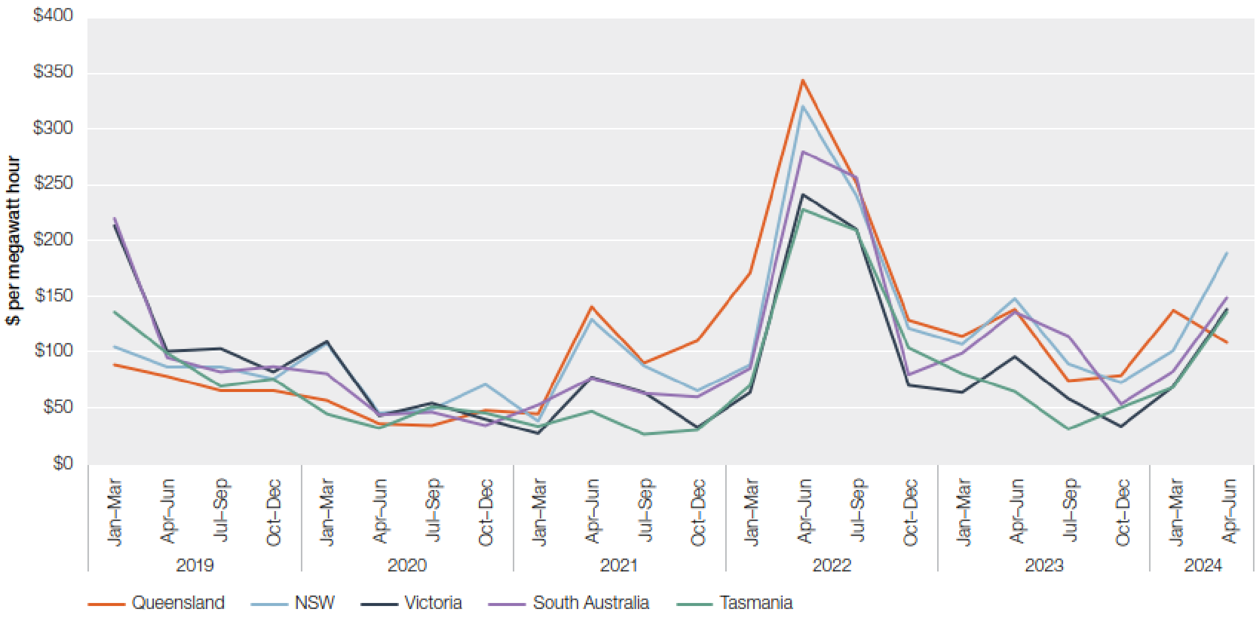
A.2.3 Contract market costs versus spot market costs

Electricity spot prices are volatile and can change rapidly in response to variations in supply and demand, with prices able to fluctuate between the Market Floor Price (MFP) of – 1000 $/MWh and the Market Price Cap (MPC) of 17,500 $/MWh. To manage price risk, or the risk that the wholesale cost of electricity in the spot market in any interval may be higher than the cost of energy that is sold to customers in contracts, retailers engage in hedging strategies.

Derivative markets help retailers to manage price risks in the wholesale market. ASX electricity futures contract data provides an indication of the interaction between spot prices and contract prices.

Figure A-3 and Figure A-4 show historical quarterly wholesale spot prices and Quarterly Base Futures prices respectively. Contract prices demonstrate analogous seasonality and volatility patterns to those evident in spot prices and are generally reflective of spot market conditions at the time of contract purchase. This is evident in the alignment of the peaks and troughs in quarterly wholesale and base futures prices. An interesting trend that emerges from the data is that following the energy crisis in 2022, both spot prices and contract prices continue to remain elevated above historical prices, indicating that historical volatility may also have a bearing in the determination of present and future spot and contract prices.

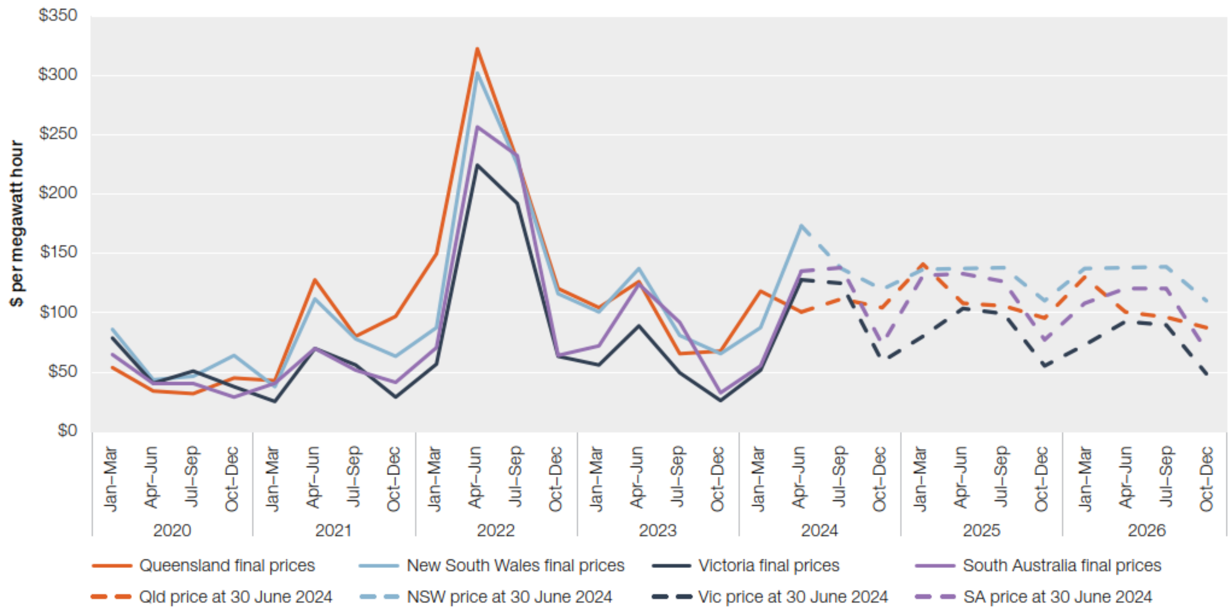
Figure A-3. Volume-weighted average quarterly wholesale prices, for the period spanning 2019 – Jun 2024.



Source: AER, State of the energy market 2024, 7 November 2024, p.19

[33] Ibid.

Figure A-4. Quarterly Base Futures prices, for the period spanning 2020 – 2026. Prices finalised to 30 Jun 2024.



Source: AER, State of the energy market 2024, 7 November 2024, p. 31

We can also observe from historical spot and contract prices the existence of a contract premium, or additional cost within electricity contracts over and above spot prices, that reflects, amongst many factors, the supply and demand for contracts and the value in a fixed price instrument versus floating price exposure.

Historical analysis of spot prices between Jan 2017 and Jul 2023 (excluding 2022) and ASX quarterly contract prices between Q1 2017 and Q3 2024 allowed the AEMC in its *2024 Residential Electricity Price Trends* report to determine average historical contract premiums for quarterly base futures, cap, and options contracts. These are shown in Figure A-5.

Figure A-5. Historical contract premiums Jan 2017 to Jul 2023 (excluding 2022), and historical ASX quarterly contract prices between Q1 2017 and Q3 2024.

State	Base Premium	Cap Premium	Option Premium	Option Purchase Price
NSW & ACT	$13.3	$3.9	6.5%	$6.9
QLD	$7.1	$2.5	15.3%	$4.7
SA	$23.7	$3.1	-	-
VIC & TAS	$10.9	$4.7	6.2%	$5.0

Source: AEMC, 2024 Residential Electricity Price Trends Methodology Report, 28 November 2024, p. 17

It is these premiums that lead to the additional cost in the wholesale element of the bill, which the AEMC estimates to be 15% of wholesale costs, with spot prices comprising 80%. Jacobs, in our analysis, have not modelled any changes in these contract premiums as a consequence of changes in spot prices. Baseload premiums vary with the overall price level and cap and option premiums also vary with volatility and price action above the excise level.

The AER and AEMC wholesale energy cost methodologies adopt book build assumptions based on commonly contracted derivative products and their historical contract volumes. This is to reflect the contracting strategies of retailers in the period prior to the delivery of electricity to end users.

The AEMC's 2024 Residential Electricity Price Trends hedging methodology adopts a combination of base swaps and options to cover average PoE10 load in each quarter, with caps covering the difference between average daily maximum PoE10 load and average PoE10 load over the quarter. Contract costs are then determined based on assumed contract volumes and weighted contract prices over the contract book build period in the lead up to delivery of electricity to the end user[34].

The AER DMO 6 determination features the use of base contracts and cap contracts in their book build, with base contract volumes up to the PoE50 off peak load, with cap contracts covering the difference between this level and 100% of the PoE50 annual peak load levels for most distribution networks (or 90% for Energex). The book build length assumed in DMO 6 is assumed to be long enough to include all trades available on the ASX. Contract prices used in their modelling are historical trade-weighted average settlement prices of futures contracts and exercised base options. Using these assumptions, 583 simulations are performed and the 75th percentile of the different cost forecasts is taken as the final wholesale energy cost.

In this report, Jacobs does not perform a two year book build to forecast future hedging costs. The snapshot analysis performed looks at a single financial year – FY 2030. This is chosen to represent probable price changes from the change in policy over the full timeframe to 2030. The change in spot prices between scenarios is seen to represent the likely uplift in contracted wholesale costs between the 2024 ISP Step Change scenario and the scenarios with a restricted renewables build-out.

A.2.4 Other wholesale costs

In addition to electricity purchase costs, other wholesale costs include: market fees, which allow AEMO to recoup their operating expenses; the cost of network losses; and the cost of ancillary services and directions, which are provided by AEMO to maintain secure operation of the power system. Other wholesale costs only account for a small proportion of the total wholesale cost (~5%).[35]

A.3 Network costs

Network costs are typically the largest component of the residential electricity bill, accounting for as much as 46% of a residential customer's electricity charges in 2023[36]. Network costs comprise Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges, accounting for the cost of accessing the transmission and distribution networks in transporting electricity to the end-user's point of connection.

To ensure consumers do not pay more than necessary for network services, network costs are closely regulated by the AER and enforced in the form of revenue caps, which are updated by the AER every five years.

The maximum revenue a network service provider (NSP) can collect from its customers is determined by the AER using a cost stacking approach. Specifically, it determines the total revenue each NSP can make to cover the following:

- Return of capital and debt.
- Return on capital.
- Operating expenses.
- Taxation.

[34] Weighted contract price: Unweighted contract prices are calculated in each of the 36 months included in the book build, as the spot price + contract premium. The final weighted contract price is determined by weighting the unweighted contract prices in each month by the percentage of the total contract volume contracted in the given month.

[35] Ibid.

[36] AER, State of the energy market 2024, 7 November 2024. p. 96

Following this, any adjustments to account for under- or over-recovery of revenue in the preceding period, as well as adjustments for rewards or penalties earnt through incentive schemes, are applied to inform the final revenue cap for each distribution/transmission business.

In addition to costs falling under the above categories, TUoS also includes the cost of regulated interconnectors that may be used in delivering electricity to the residential customer.

A.4 Environmental costs

The costs associated with national and jurisdictional environmental schemes are primarily covered by retailers and other eligible companies, with costs paid by each party proportionate to their non-exempt wholesale energy acquisitions (where non-exempt acquisitions refer to total customer demand minus any Emissions Intensive Trade Exposed (EITA) consumption).

The Renewable Energy Target (RET) is a key nationwide scheme which aims to accelerate Australia's transition to a low carbon generation mix. The scheme, for which participation is mandatory, financially supports the delivery of an additional 33,000 GWh of electricity from renewable generation yearly until 2030. The RET has two arms: the Large-Scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES), the former encouraging the development of large-scale renewable generation, and the latter stimulating consumer investment into small-scale renewable technologies. Every year, retailers are required to surrender a proportionate amount of Large-Scale Generation Certificates (LGCs) and Small-Scale Technology Certificates (STCs) to the Clean Energy Regulator (CER), under the LRET and SRES respectively, for electricity used by their customers.

At the jurisdiction level, 'green' schemes, which harness energy efficiency and demand-side flexibility at the consumer level, are put in place to assist in the management of load profiles. Retailers in relevant jurisdictions have obligations to either buy scheme certificates or participate directly in its activities.

AEMC 2024 Price Trends forecasts that, with some mandatory environmental schemes supporting government targets, including the RET, due to end in 2030, environmental costs are expected to decrease significantly from FY 2030 onwards. The costs associated with voluntary schemes anticipated to kick in during the 10-year forecast period to 2034, such as the Renewable Energy Guarantee of Origin (REGO) scheme, are not included in the calculation of the above forecast, due to the difficulty of predicting participation levels in such schemes.

A.5 Retail costs

Retail costs include:

- Costs of providing service, which are costs incurred for activities such as billing, running call centres, hardship programs and debt collection.
- Costs of acquiring and retaining customers, including costs associated with advertising and marketing campaigns.
- Smart meter costs (in all jurisdictions except for Victoria).
- Retail margin .

Retailer costs vary year on year, influenced by a host of factors. For instance, costs of debt collection and hardship services, included under the costs of providing service, depend on economic climate and labour costs. Meanwhile smart meter costs, including costs for deployment and maintenance, are largely governed by regulatory requirements. With the AEMC's recently announced accelerated smart meter deployment scheme requiring the universal deployment of smart meters by 2030, a corresponding increase in smart meter costs is anticipated as deployment takes place, until 2030, after which smart meter costs are anticipated to stabilise. Retail margins are influenced by a mix of factors, including wholesale market volatility and a retailer's ability to successfully hedge against unprecedented volatility events.

While the above drivers may lead to year-on-year fluctuations in retail costs, it is important to note that retail costs account for a relatively small portion of the residential electricity bill, assigned 12% of the maximum standing offer for residential customers in DMO 6[37]. In fact, the AEMC forecasts in the 2024 Price Trends report that retail and metering costs are expected to remain relatively flat, decreasing slightly over the timeframe to 2034.

[37] AER, Default Market Offer Prices 2024-25: Final determination, 3 June 2024, p. 3

Appendix B. Gas Demand and Supply Balance

B.1 AEMO ISP 2024 and GSOO 2024 Gas Price Overview

The AEMO 2024 ISP gas price assumptions were provided by ACIL Allen in July 2023 for gas-fired generation in the NEM[38]. Some of the key assumptions from ACIL Allen for the Step Change scenario include:

- The gas price forecasts represent the marginal prices for new wholesale gas supply, and not the average cost of wholesale gas in the east coast gas market.
- The global long-term oil price is US $65/barrel.
- The Port Kembla LNG terminal is online from 2028.
- Expected long run average of $11/GJ for LNG price in the Step Change scenario.
- Levels of reserves and resources of gas supply by basin is the same across all scenarios (in PJ) and aligns with the AEMO's data used for the Gas Statement of Opportunities report. Acil Allen anticipated the following sources of supply to enter the market: LNG imports at Port Kembla, the Narrabri Gas Project, offshore Victorian supply projects and some supply from the Beetaloo Basin from the 2030s.
- The changing east coast gas market dynamics, which is currently directly connected to the international LNG markets, compared to previous long-term bilateral agreement contracts between producers and consumers.
- Declining residential and commercial domestic demand of 150 PJ is projected by the mid-2030s.

Overall, for the Step Change scenario, the prices for gas-powered generation are expected to decline to levels around $10/GJ to $12/GJ in the late 2020s and early 2030s, before rising steadily to $11/GJ to $15/GJ by the end of 2050s.

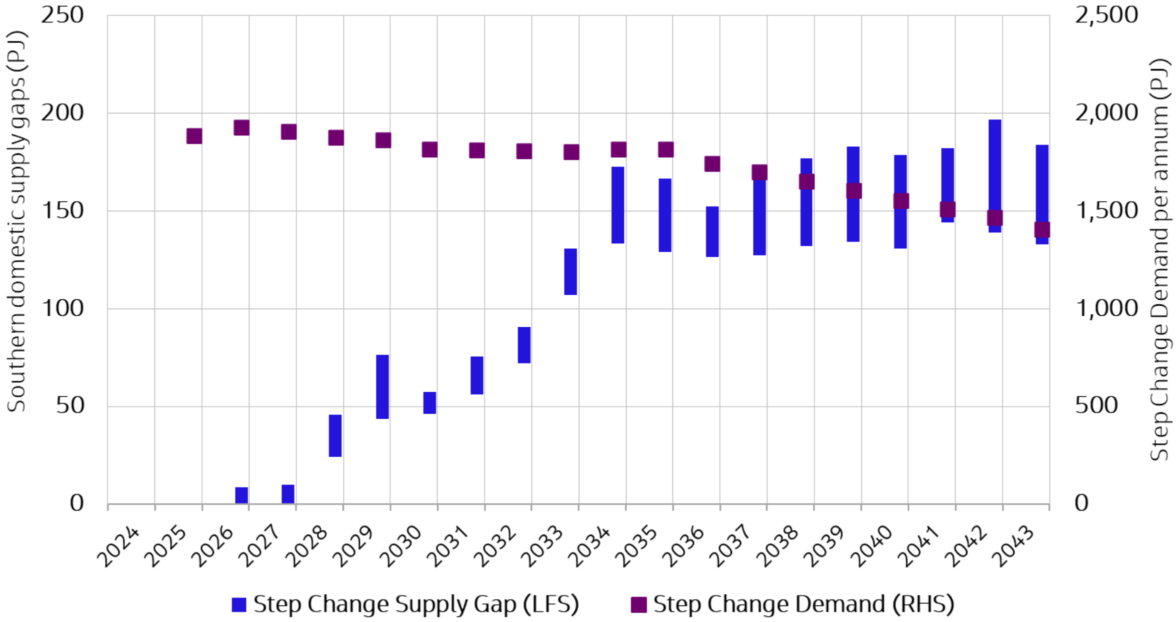
B.2 GSOO 2024 demand supply balance

In the latest GSOO 2024, the east coast gas market is expected to experience gas supply inadequacy from 2025 onwards, with forecast annual supply gaps from 2028 onwards. The following chart represents the demand supply datapoints for the Step Change Scenario, where the supply curve is represented with gaps for the respective year against its total demand (GPG included)[39]. The supply forecast in the southern regions is based on existing, committed, and anticipated developments, which includes the LNG terminals further discussed below.

[38] The ISP 2024 used the 2023 IASR assumptions. Jacobs noted that AEMO has since published 2025 IASR which is going through consultation: https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr

[39] Supply data points are represented by supply gaps, rather than total supply in PJ per AEMO's GSOO 2024 documentation

Figure B-1. Total yearly demand and supply gaps, in PJ, for GSOO 2024 Step Change Scenario

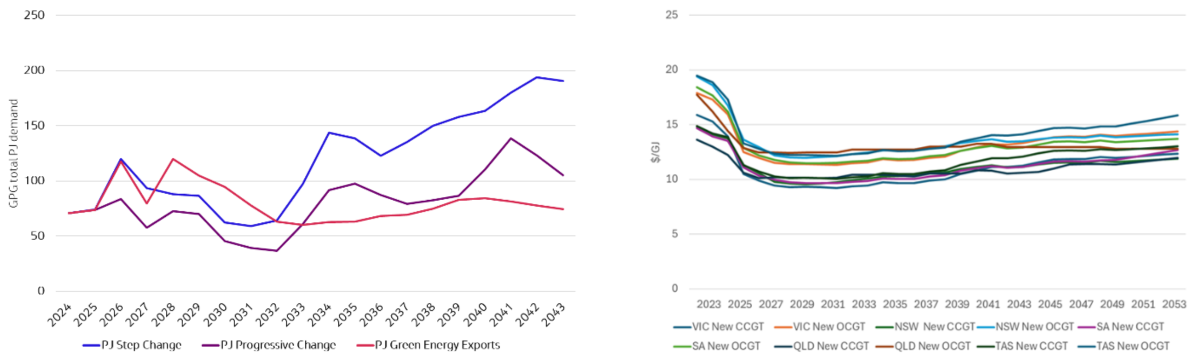


Source: Jacobs analysis of ISP 2024 and GSOO 2024 data and scenarios

The supply gaps identified in the Step Change scenario are the highest in cumulative total, compared to all other scenarios in GSOO 2024.

For AEMO's GSOO 2024, the total gas demand for GPG in the Step Change scenario, together with gas price for new GPG facilities as considered by AEMO are illustrated below.[40]:

Figure B-2. GPG gas demand usage in ISP 2024 and corresponding GSOO 2024 scenarios, new GPG gas price assumptions GSOO 2024



Source: Jacobs analysis of ISP 2024 and GSOO 2024 data and scenarios

The GSOO 2024 provided the demand and supply balance based on the scenarios above. Based on the current available gas supply, gas shortfalls are expected from 2025 onwards on extreme peak demand days. In the step change scenario this reaches 63 PJ in 2030, any gas demand for generation above these levels will likely see a more constrained gas market.

Analysing the supply curve provided by AEMO, the expected shortfalls will need to be met by as yet undeveloped sources, including LNG import facilities.

[40] The PJ required across all Step Change sensitivities (Step Change, Step Change – DRI, Step Change – Net, Step Change – No Electrification) is the same