Report to the Independent Review into the Future Security of the National Electricity Market

Emissions mitigation policies and security of electricity supply

Report

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Emissions mitigation policies and security of electricity supply

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Revisions: Readers should note that on page 59 of the report a typographical error has been corrected regarding the resource costs for the BAU scenario. They were previously reported to be $135 billion instead of $132 billion. This correction does not affect the conclusions of the report.

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The sole purpose of this report and the associated services performed by Jacobs is to assess the electricity sector impacts of policy scenarios to reduce emissions of greenhouse gases in accordance with the scope of services set out in the contract between Jacobs and the Client. That scope of services, as described in this report, was developed with the Client.

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Executive Summary

The Independent Review into the Future Security of the National Electricity Market (Finkel Review) has engaged Jacobs to undertake a study of the potential impacts on electricity markets of a range of policies to meet stated targets in relations to greenhouse gas emissions. This report outlines the findings of this study.

The policies examined were:

- A Business as Usual (BAU) approach which modelled a market where there was continuing uncertainty over the form of abatement policy increasing the uncertainty around investment decisions and maintenance programs for existing plant. This scenario acted as a reference case for all other policy approaches examined.

- A Clean Energy Target (CET) that specified a target level of low emissions generation geared to meeting annual emissions targets.

- An Emissions Intensity Scheme (EIS) which provided rewards and penalties to plant depending on plant’s emissions intensity relative to a baseline intensity for the electricity sector. The baseline intensity was gradually reduced to meet the emissions target.

- Limited Lifetime (LL) approach where thermal generating plants were mandated to close at 50 years of operating life.

- A Clean Energy Target with a Limited Lifetime (LLCET) where the clean energy target was set to achieve the residual level of abatement required that was not achieved from the mandated closure of generating plants.

- An Emissions Intensity Scheme with a Limited Lifetime (LLEIS) where the emissions intensity target was set to achieve the residual level of abatement required that was not achieved from the mandated closure of generating plants.

Details of the approach and assumptions used to model the impacts are outlined in the body of this report.

Key results

Under the Business as Usual scenario, wholesale electricity prices and the economic costs of supplying electricity is elevated due to the lower availabilities of the coal plant and the higher risk premium due to policy uncertainty that applies to new plant.

Economic (resource) costs under the policy scenarios are generally higher than for the Business as Usual scenario. The lowest cost options for the policy scenarios are for an EIS scheme, followed closely by the CET scheme. Costs are increased where a limited lifespan is applied to existing generators, as this brings forward the cost of investment in new plant and increases the level of that investment. Limiting lifetimes also increase the need for new dispatchable plant – typically higher cost gas-fired plants - that can meet demand in periods when renewable energy is not generating.

In all scenarios, the level of coal-fired generation diminishes over the modelling period. The extent and pace of the fall in generation depends on the extent of restrictions on lifespan and the interaction of the policy measure with wholesale prices.

The level of renewable generation increases under all scenarios. Even without additional policy support under the BAU scenario, declining costs means that it is least cost for some level of renewable generation to enter the market.
However, some form of dispatchable generation is required from around 2030 onwards to fill the gap in meeting demand when renewable sources are not generating. This role is undertaken by gas-fired generation when the life of coal plant is limited but is filled largely by existing coal plant otherwise. Uptake of energy storage also occurs to fulfil this function.

Although emissions are reduced under all scenarios, the 2030 target is not met without some additional policy support. Limiting the life of the generating plants is not sufficient to meet the target to 2030, but the large amount of retirements post 2030 do mean that the emissions trajectory used in the modelling post 2030 is met.

Hence, additional policy measures are required to meet targets to 2030. The 2030 target is met under both the CET and EIS policies.

Wholesale prices are similar across the scenarios except for the CET and EIS scenarios, where the additional incentives provided to low emissions plants puts downward pressure on wholesale prices.

Retail prices are lower under the CET and EIS than all other scenarios even when taking into account the compliance costs of the CET scheme. The CET scenario had lower retail prices than for the EIS scenario.

**Generation and capacity**

The generation mix across the scenarios is impacted by the assumed lifespan for generating plant and the extent of support provided to low emissions technologies under the policy measures.

Limiting the lifetimes of coal-fired plants affects the extent of uptake of gas-fired generation and renewable energy generation. Coal-fired generation is generally highest under the BAU scenario until around 2040, when the bulk of the fleet retires. The level of coal fired generation across the scenarios in which the lifetime of coal-fired plant is limited to 50 years is fairly similar, showing a sharp reduction of generation levels after 2030 when a large part of the fleet reaches 50 years. Under the CET and EIS scenarios where a limited lifetime is not imposed, coal generation is maintained and has a more gradual decline as the existing plants undertake the task of meeting demand when renewable energy generation is not available.

Levels of gas-fired generation are dependent on the level of retirement of coal plants. When coal plants retire, gas-fired generation is required to meet the gap between demand and available renewable energy generation. In the cases where the coal fleet is retired at 50 years of operation, the level of gas-fired generation trebles from 2035 onwards. Where there is no limited lifetime applied to coal plant, the level of gas fired generation is stable across the modelling period and the existing coal fleet is used to meet demand when there is not enough renewable energy generation or energy storage.

Renewable energy generation expands across all scenarios, with the rate of expansion depending on the level of policy support. The highest level of growth occurs under a CET and EIS schemes.

**Emissions**

Emissions are projected to fall across all scenarios with the rate of the fall dependent on the policy approach. Emissions fall in the BAU but not enough to meet the annual emissions targets. Just requiring plants to close at 50 years of age does not meet the annual targets until after 2030 when a large portion of the coal fleet retires.

By design, the CET and EIS schemes meet the required annual targets across the entire period to 2030. However, combining these policies with limited lifetime for generating plant means there is more abatement than the trajectory level after 2030. With limited lifetimes imposed on power plants, there is a prolonged period when the EIS or the CET is not required to meet the emissions target.
Prices

Wholesale prices are projected to be similar across the Business as Usual and scenarios with a limited lifetime imposed on generating plant. Under these scenarios wholesale electricity prices rise gradually from 2020 onwards plateauing at around $90/MWh.

Wholesale prices are lower under the CET and EIS scenarios (without limited lifetime imposed). Both schemes provide an additional revenue stream for low emissions generation to enter and this reduces prices either by the greater penetration of plant with zero dispatch costs or because plant reduce their dispatch bid to reflect the value of earning certificates. Prices are lowest for the CET because there is no direct penalty applied to existing coal-fired generators as under the EIS, which also means that there is no distinction between black coal and brown coal under the CET as there is under the EIS. Further, under an EIS, the revenue earned by gas-fired generators through certificates reduces over time as the sectoral baseline reduces.

Retail price trends follow trends in wholesale prices. Retail prices for a CET and EIS scheme (without any limited lifetime applied on plant) are lower than for the other scenarios but the gap (evident in the wholesale prices) between the CET and EIS schemes is reduced as the cost of certificates are added onto retail prices under the CET scheme\(^1\). Residential retail prices for these two schemes are on average around 7 per cent to 10 per cent lower than for other scenarios. The retail price for the CET is around 3 per cent lower than the EIS scheme over the modelling period under the assumptions used in the modelling. Industrial retail prices for the CET and EIS schemes are also lower than in other scenarios (over 10 per cent on average) with prices under the CET scheme being lower than the EIS scheme on average.

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\(^1\) As certificates are traded amongst generators in an EIS scheme, the certificate cost is not assumed to be passed onto to the retail prices except so far as they impact on wholesale price.
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Table 1: Residential retail price outcomes

<table>
<thead>
<tr>
<th>Scenario</th>
<th>c/kWh</th>
<th>% change from BAU</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>2020-2030</td>
<td>2020-2050</td>
</tr>
<tr>
<td>BAU</td>
<td>30</td>
<td>31</td>
</tr>
<tr>
<td>CET</td>
<td>28</td>
<td>28</td>
</tr>
<tr>
<td>EIS</td>
<td>29</td>
<td>29</td>
</tr>
<tr>
<td>LLCET</td>
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<td>31</td>
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<tr>
<td>LLEIS</td>
<td>30</td>
<td>31</td>
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Resource costs and abatement cost

All policy scenarios have higher resource costs than for the BAU due to higher levels of gas-fired generation (hence higher fuel costs) or additional capital expenditure on new plant, or both.

Of the policy scenarios, the EIS scheme has the lowest resource costs. The resource costs over 33 years to 2050 under this scenario are around $3.5 billion higher than in the BAU scenario when using a 7% discount rate. Resource costs are higher under a CET scheme due principally to more investment in new plant, with resource costs estimated to be around $5 billion higher than the BAU when using a 7% discount rate. For all other policy scenarios, the difference is greater than $12 billion.

Figure 2: Resource costs relative to the Business as Usual, all scenarios (2017-2050)
The cost of abatement for the policy scenarios are shown in Figure 3. For all the policy cases that are meeting the 28% emissions target reduction the abatement costs are following the trends of the resource costs. The EIS policy has the lowest cost (around 7.5 $/t CO\textsubscript{2}-e), followed by the CET policy with 10.5 $/t CO\textsubscript{2}-e. The other scenarios have abatements costs ranging from 17.5 $/t CO\textsubscript{2}-e to 21.1$/t CO\textsubscript{2}-e, while it should be noted that the Limited Lifetime policy does not meet the 28% emissions reduction in the NEM on 2005 levels by 2030.

Figure 3: Cost of abatement relative to the Business as Usual, all scenarios (2017-2050)
## Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>BAU</td>
<td>Business as Usual</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
</tr>
<tr>
<td>CET</td>
<td>Clean Energy Target</td>
</tr>
<tr>
<td>DLF</td>
<td>Distribution loss factor used to adjust price received according to losses in the distribution and sub-transmission system relative to the transmission connection point.</td>
</tr>
<tr>
<td>EIS</td>
<td>Emissions Intensity Scheme</td>
</tr>
<tr>
<td>ESOO</td>
<td>Electricity Statement of Opportunities, documents published annually by AEMO to provide information on the demand and supply situation in the NEM</td>
</tr>
<tr>
<td>LGC</td>
<td>Large-scale generation certificates (formerly REC) under RET</td>
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<tr>
<td>LL</td>
<td>Limited Lifetime</td>
</tr>
<tr>
<td>LRET</td>
<td>Large-scale Renewable Energy Target under RET</td>
</tr>
<tr>
<td>MLF</td>
<td>(Transmission) Marginal Loss Factor applied to adjust price received according to network power losses relative to the regional reference node.</td>
</tr>
<tr>
<td>RET</td>
<td>Renewable Energy Target enacted under the Renewable Energy (Electricity) Act 2000</td>
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<tr>
<td>NEM</td>
<td>National Electricity Market</td>
</tr>
<tr>
<td>NEFR</td>
<td>National Electricity Forecasting Report</td>
</tr>
<tr>
<td>POE</td>
<td>Probability of Exceedance</td>
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<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RECs</td>
<td>Renewable Energy Certificates</td>
</tr>
<tr>
<td>REMMA</td>
<td>Jacobs’s renewable energy market model for Australia’s large scale renewable energy target</td>
</tr>
<tr>
<td>SRES</td>
<td>Small-scale Renewable Energy Scheme under RET</td>
</tr>
<tr>
<td>TUoS</td>
<td>Transmission use of system charges</td>
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1. **Overview**

1.1 **The Finkel Review**

The Independent Review into the Future Security of the National Electricity Market (Finkel Review) has engaged Jacobs to undertake modelling of a potential range of policies to meet the Government’s policies and targets in relation to emissions reduction.

Chapter 1 discusses the market modelling method that is employed in the study and the assumptions that underlie Jacobs’ electricity market modelling suite. It also describes the policy options that are modelled and the main design features. All modelling is conducted in June 2016 dollars, and years referenced refer to financial years ending in June, unless otherwise stated. For example, 2017 refers to the period from 1 July 2016 to 30 June 2017.

1.2 **Modelling Approach**

1.2.1 **Software tools and method**

Jacobs is using a suite of two models to determine the least cost generation mix in the electricity sector - that is, the electricity sector investments required to satisfy demand at least cost for society as a whole given input prices and policies. This requires iterations between the two models to determine both the direct impacts and interactions between the electricity market and the various ancillary markets used as instruments to meet the emissions constraint.

The two models are:

- Strategist - the electricity sector dispatch and investment model.
- REMMA - the renewable energy market model.

*Figure 4: Modelling approach*
The approach to modelling the electricity market impacts, associated fuel combustion and emissions is to utilise externally derived electricity demand forecasts (adjusted for the embedded generation component) in our Strategist model of the NEM. Strategist accounts for the economic relationships between generating plants in the system. In particular, Strategist calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs or bids of each generating plant in the system to match the demand profile, assuming a sufficient level of competition to drive efficient dispatch.

The iterative approach is as follows:

- An initial estimate of total electricity demand and retail price projections are used to work out the level of embedded generation each year and the level and timing of new large-scale renewable generation.
- The level of embedded generation determines the net demand for electricity faced by the electricity grid, which is input into the electricity market models.
- The level and location of new large-scale renewable generation (from REMMA) is also input into Strategist.
- Strategist then simulates the response of the thermal generation and hydro-electric plants to produce a new set of wholesale and ultimately retail price projections.
- The whole process is repeated until a stable set of wholesale prices and renewable energy mix by region is achieved.

Further details on the models are included in Appendix A.

1.2.2 Emissions constraint

The target employed was designed to achieve a 28% emissions reduction in the NEM on 2005 levels by 2030, and then continuing in a linear decline to zero by 2070.

Figure 5: Emissions targets

-28% of 2005
emissions by 2030 = 127 MtCO₂-e

Emissions in 2050 = 63 MtCO₂-e

-28% by 2030 then zero by 2070
1.2.3 New generation

The dynamic programming method in Strategist selects new capacity on a least-cost basis (refer to Appendix A). The model is generally accurate in the prediction of the future generation mix, with the main deviations from projected investment the result of:

- Economies of scale in plant sizing
- Pre-emptive entry of new plant which may see plant enter the market earlier than required to lock out entry of other competing new options.
- Fuel supply arrangements where additional capacity can reduce the per unit cost of fuel supply.

1.2.4 Retirements

Plant retirements are analysed manually after the expansion plan and pricing is developed in the Strategist model. Plant is retired if its avoidable operating cost exceeds its pool revenue, allowing for some contracting premium on the pool revenue. The closures of Northern in South Australia, Smithfield in New South Wales and Hazelwood in Victoria have been included in the modelling. More information is provided in section 3.2.4.

1.2.5 Interconnection development

Interconnection upgrades are included in the Strategist modelling as development options in competition with new generation capacity. This is further discussed in section 3.4.

1.2.6 Renewable energy target

An overview of the renewable energy target is provided in section 3.5.1.

The large scale renewable energy target (LRET) profile used for the modelling is shown in Figure 6 by calendar year as modelled in REMMA. This shows the raw LRET target trajectory, as well as additional demand for renewable energy driven by GreenPower as well as estimated demand from water desalination facilities and the 100% ACT renewable energy target.

LGC demand will no longer be a driver for new investment in renewable energy post 2020. Long term demand for renewable electricity will be based on trends in technology costs and continuing development in government policy, with a view to long-term emissions abatement.

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2 AGL recently announced that it will defer the proposed 2017 mothballing of Torrens Island A power station. See https://www.agl.com.au/about-agl/media-centre/article-list/2016/june/agl-to-defer-mothballing-of-south-australian-generating-units. We have therefore kept operating Torrens Island until it retires due to reaching end of life or it is found to be not economic.
1.3 Interpreting this modelling

The modelling is designed to provide insights into the potential impacts of alternative policy measures to achieve a given emissions constraint. The modelling approach is based on standard and long used methods.

The modelling makes a range of assumptions and simplifications in order to provide information about the relative performance of possible policies to reduce emissions. The modelling omit features such as ramp rate constraints and start-up costs that are important for short-term outcomes in the electricity sector, but are small in absolute terms over the longer time horizons that are the focus of this work, so excluding them will not materially affect the comparative projections in this report. Some assumptions, however, such as the level of electricity demand and the availability and costs of electricity generation technologies, are important for the results.

The level of uncertainty around the results increases over the modelling horizon.

The results of the modelling should be interpreted carefully to account for the broad context and the limitations of the modelling. Important points to note are:

- The results are projections for illustrative scenarios. They are not forecasts of likely future outcomes.
- The modelling assumes perfect foresight with future trends in key assumptions known with certainty. Investment decisions, for example, are made with complete knowledge of future fuel and capital costs. In reality, future trends in key assumptions are not known and investors take into account the uncertainties when making their investment decisions.
- The modelling does not include some potential future costs that may affect coal-fired generation such as social costs and random events (health and safety issues, old machines’ parts that are no longer produced, etc.)
- In each policy scenario, all policies are assumed to be perfectly credible.
- The modelling presumes the policy is announced in 2018, with a start date in 2020. This allows for an immediate reaction in 2020 if required. In reality, reaction times may be longer than presumed.
- Many of the policies result in rapid construction to replace the coal fleet in a short space of time. In practice this rapid construction may increase the price of inputs due to ‘bottlenecks’ in construction. As
these increases would be reasonably uniform across scenarios and small relative to the large overall levels of investment across the scenarios, they were not estimated here.

- The modelling assumes policies are set for the period from 2020 to 2050. In reality, the policies may evolve over time as attention is given to meeting emissions constraints beyond 2050.
- The modelling does not incorporate the second-round or indirect impacts of these policies on the wider economy.
- Short run constraints on the availability of gas are assumed not to persist beyond 2019.
2. **Modelled Scenarios**

The scenarios modelled and some of the key assumptions used are summarised in Table 2 below.

**Table 2: Scenarios and sensitivities modelled and key assumptions used**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Target in 2030</th>
<th>Security constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>Business as Usual (BAU)</td>
<td>Not applicable</td>
<td>No</td>
</tr>
<tr>
<td>Clean Energy Target (CET)</td>
<td>28% below 2005 levels</td>
<td>No</td>
</tr>
<tr>
<td>Emissions Intensity Scheme (EIS)</td>
<td>28% below 2005 levels</td>
<td>No</td>
</tr>
<tr>
<td>Limited Lifetime (LL)</td>
<td>No target</td>
<td>No</td>
</tr>
<tr>
<td>Limited Lifetime and Clean Energy Target (LLCET)</td>
<td>28% below 2005 levels</td>
<td>No</td>
</tr>
<tr>
<td>Limited Lifetime and Emissions Intensity Scheme (LLEIS)</td>
<td>28% below 2005 levels</td>
<td>No</td>
</tr>
<tr>
<td>Limited Lifetime and Clean Energy Target with minimum synchronous generation constraint (LLCETs)</td>
<td>28% below 2005 levels</td>
<td>Yes</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Application</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>10% probability-of exceedance (POE) for the median peak demand</td>
<td>Applied to all the previous modelling runs</td>
<td>Determines the extra capacity needed to meet this higher peak demand</td>
</tr>
</tbody>
</table>

2.1 **Policy design features used for the modelling**

The specific modelling design features for the different policies are described below while a summary of all these features is also given in Appendix B.

**Overarching issues**

- The modelling covers the National Electricity Market.
- No assistance is considered for the Emissions Intensive Trade Exposed Industries (EITE), since it has no direct impact on the cost of policies but only to the distribution of costs.
- The existing Renewable Energy Target remains as it is for all scenarios. Under the CET scenarios, the LRET operates separately.
- All the new emissions reduction policies are implemented from financial year 2020 onwards.
2.1.1 **Business as Usual**

The Business as Usual (BAU) scenario includes the uncertainty that investors and plant owners face regarding emissions reduction policy. The uncertainty arises because there is the view that a carbon mitigation policy may be introduced in the future, but the timing and extent of any policy are uncertain.

There are two elements to the approach to modelling uncertainty.

1) **Adjusting the weighted average cost of capital (WACC) for different technology types**

A different WACC is applied to different technologies in recognition that more emissions-intensive generators face greater investment risks than low emissions generators. Different generation technologies have a risk premium added to both the cost of debt and equity in proportion to the emissions intensity of the technology.

Projects that are seen as greater risk (higher emitting generators) will likely have a smaller share of debt funding as compared to lower emitting generators. Some projects also have higher finance costs due to the market or project risks they face due to their size, complexity of technology or because they have a high proportion of upfront capital costs.

For the BAU case the WACC for different technologies are outlined in Table 3. Elements of the WACC calculations were reviewed by the CEFC and ARENA.

**Table 3: Weighted cost of capital for different technologies in the BAU case**

<table>
<thead>
<tr>
<th>Generator</th>
<th>Coal</th>
<th>Gas CCGT</th>
<th>Renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt to equity ratio</td>
<td>40:60</td>
<td>75:25</td>
<td>75:25</td>
</tr>
<tr>
<td>Risk premium</td>
<td>5%</td>
<td>2%</td>
<td>1%</td>
</tr>
<tr>
<td>Cost of debt</td>
<td>5.3%</td>
<td>4.4%</td>
<td>4.4%</td>
</tr>
<tr>
<td>Cost of debt (including risk premium)</td>
<td>10.3%</td>
<td>6.4%</td>
<td>5.4%</td>
</tr>
<tr>
<td>Cost of equity</td>
<td>13%</td>
<td>11%</td>
<td>11%</td>
</tr>
<tr>
<td>Cost of equity (including risk premium)</td>
<td>18%</td>
<td>13%</td>
<td>12%</td>
</tr>
<tr>
<td>WACC</td>
<td>14.9%</td>
<td>8.1%</td>
<td>7.1%</td>
</tr>
</tbody>
</table>

*Note: All the WACC figures shown are pre-tax and adjusted for inflation.*

2) **Deferred maintenance on emissions-intensive generators**

Coal generators usually have maintenance cycles every four to six years and more substantial half-life refurbishments periodically. These maintenance cycles and half-life retrofits restore (and sometimes enhance) plant availability and thermal efficiencies.

To reflect uncertainty, it is assumed that all coal-fired operators are not willing to invest in half-life retrofits and only have the option of performing the maintenance cycles to keep the plants in reasonable operating condition.

All the coal plants in the NEM are assumed to undergo an economic assessment after they reach 35 years of operation to decide whether they will proceed with their maintenance cycle or not. For each maintenance cycle (after 35 years), coal plants typically have three choices:

- No maintenance.
Emissions mitigation policies and security of electricity supply

- Minor refurbishment.
- Major refurbishment (full restoration of performance through a half-life retrofit).

In the BAU scenario, the choice is confined to no maintenance and minor refurbishments – major refurbishment (full restoration of performance) is assumed not to proceed in this uncertain world due to their relatively high cost. The economic assessment is done on the basis that additional profits repay maintenance costs within a 5 year payback period.

The plants where it is economically optimal to implement minor refurbishments have a 0.5 percentage point reduction of their thermal efficiencies\(^3\) and availabilities\(^4\) for the next 5 years. For example, if the efficiency of a coal plant is 80% at the time of the minor refurbishment, in five years’ time it will be 79.5% (0.1 percentage point decrease each year). That is because the type of refurbishment undertaken is not a major refurbishment but rather a minor refurbishment to keep the plant in reasonable operating condition. After that a new assessment is performed again at 5 year intervals.

The plants where it is not economic to implement a minor refurbishment will not perform them and their thermal efficiencies and availabilities decrease by 5 percentage points for the next 5 year period (1 percentage point each year). So, if a plant has an efficiency of 80% and does not perform a minor refurbishment, its efficiency will drop to 75% five years later. Regardless of the decision the plant makes, it has the opportunity to perform a new economic assessment for a minor refurbishment every 5 years.

All the coal plants are assumed to not operate beyond a life of 60 years or if they incur net trading losses, whichever comes sooner.

2.1.2 Clean Energy Target

The Clean Energy Target (CET) policy is administered in the same way as the large-scale renewable energy target but with wider eligibility.

Under the CET:

- The generation target is set to achieve the required emissions target in each year.
- The trajectory increases as the required emissions target reduces. The CET is focused on achieving emissions targets rather than a fixed low emissions generation target and its trajectory is adjusted each year to reflect changes in the emissions target, electricity demand and in the generation mix. The CET is technology neutral. Eligibility is extended to all new renewable generators and low-emissions generators below a threshold level of emissions intensity. Carbon capture and storage (CCS) retrofits to existing plant are also eligible.

The emissions intensity threshold is set at 0.6 t CO\(_2\)-e/MWh.

Eligible generators receive certificates for a 15 year period adjusted by how much the generation outperforms the threshold intensity, such that a zero emissions generator would receive one certificate for every MWh of output, while a generator with half the threshold intensity would receive half a certificate.

For example, Generator A has an emissions intensity of 0.3 t CO\(_2\)-e/MWh. Since the emissions intensity threshold is 0.6 t CO\(_2\)-e/MWh, Generator A will earn 0.5 certificates for each MWh generated since \( (0.6 - 0.3) / 0.6 = 0.5 \)

\(^3\) That is, their heat rate (in GJ/MWh).
\(^4\) That is, the amount of time in a year they are available for dispatch. It represents the time available after forced outage rates and planned maintenance cycles are deducted.
The scheme covers all the generators on the NEM but excludes generators already receiving a subsidy through the existing Large-scale Renewable Energy Target scheme.

To avoid windfall gains for pre-existing generation, zero- and low emissions generators existing at 2020 are eligible to produce CET certificates only for any generation above their historic baselines.

The CET trajectory grows from zero in 2020 and continues to rise to 2050, with the level of the CET designed to achieve the emissions trajectory for every year. The model incorporates perfect foresight and allows for unlimited banking of certificates, similar to the current large-scale renewable energy target, so as to reduce price volatility. Also, the borrowing of certificates is limited to 10 per cent of the following year’s certificates in order to mitigate the risk of a shortage in available certificates.

The CET scheme is not zonal but implemented to the NEM as a whole, that is, the technology is built wherever it is most profitable to do so.

The coal-fired generators continue to perform all their scheduled maintenance and refurbishments and therefore their thermal efficiencies and availabilities remain unchanged during their operation.

### 2.1.3 Emissions Intensity Scheme (EIS)

An emissions intensity baseline is set for the electricity supply sector as a whole (based on tonnes of carbon dioxide equivalent per megawatt hour sent out (t CO₂-e/MWh)). Generators with emissions intensities below the baseline receive certificates equal to the difference between their emissions intensity and the baseline multiplied by their output. Generators with emissions intensities above the baseline must purchase and surrender certificates equal to the difference between their emissions intensity and the baseline multiplied by their output. This effectively means that generators with intensities below the baseline have surplus permits to sell (so receive a subsidy) and generators with intensities above the baseline need to buy additional permits (so incur an extra cost).

For example, if a baseline is set to 0.6 t CO₂-e/MWh for a year and Generator A has an emissions intensity of 0.8 t CO₂-e/MWh and output of 100,000 MW. Then the allocated permits are:

\[
\text{Permits} = \text{Generator A output} \times (\text{EI baseline} – \text{EI of Generator A})
\]

\[
= 100,000 \times (0.6 - 0.8) = -20,000
\]

So, Generator A has to surrender 20,000 permits.

Conversely, Generator B with an emissions intensity of 0.4 t CO₂-e/MWh and output of 100,000 MW has a surplus of 20,000 permits.

Emissions permits can also be banked indefinitely for future use or borrowed in limited quantities.

The scheme covers all the generators in the NEM.

No domestic or international offsets are allowed.

The baseline is set consistent with the emissions target being modelled and starts in 2020 at the grid average emissions intensity, declining linearly to the level necessary to meet the emissions trajectory in every year to 2050.

The coal-fired generators continue to perform all their scheduled maintenance and refurbishment and therefore their thermal efficiencies and availabilities remain unchanged during their operation.

---

5 Without banking, the price of certificates would drop to zero once demand for the year is met.
2.1.4 Limited Lifetime

The Limited Lifetime policy forces the regulated closure of existing coal-fired generators. All coal generating units that reach their 50 year economic life are required to close. The modelling assumes the closure is implemented on a unit by unit basis, 50 years after each unit’s commissioning date. Coal-fired generators continue to perform all their scheduled major maintenance refurbishments until their closure date and therefore their thermal efficiencies and availabilities remain unchanged during their operation.

High load duty gas-fired plant (such as combined plant) do not have this age limit applied principally due to the fact all these plant have been built since 2000 and do not reach 50 years of operating life until after 2050 (the end of the modelling period).

In this policy scenario there is no requirement to meet an emissions reduction target.

2.1.5 Limited Lifetime with Clean Energy Target

The Limited Lifetime with a Clean Energy Target (LLCET) policy is a combination of the two polices described above. The coal plants are forced to close on a unit by unit basis when they reach their 50 year operating life, while an additional CET policy is implemented to achieve the extra emissions reduction (i.e. not delivered by mandated closure of coal plant) required to meet the emissions trajectory.

The coal-fired generators continue to perform all their scheduled maintenance and refurbishment and therefore their thermal efficiencies and availabilities remain unchanged during their operation.

2.1.6 Limited Lifetime with Emissions Intensity Scheme

The Limited Lifetime with Emissions Intensity Scheme (LLEIS) policy is a combination of the two policies described above. The coal plants are mandated to close on a unit by unit basis when they reach their 50 year operating life, while an additional EIS policy is implemented to achieve the extra emissions reduction (i.e. not delivered by the mandated closure) required to meet the emissions target.

The coal-fired generators continue to perform all their scheduled maintenance and refurbishment and therefore their thermal efficiencies and availabilities remain unchanged during their operation.

2.1.7 Limited Lifetime with Clean Energy Target and minimum synchronous generation constraint

The Melbourne Energy Institute (MEI) was tasked to determine the level of minimum synchronous generation inertia requirements to ensure a secure system at all times in the Limited Lifetime with Clean Energy Target policy. The outcome of this MEI study provided Jacobs with yearly data for minimum synchronous generation in the form of two different values:

1. The minimum yearly online synchronous output, that represents the actual generation output from synchronous generators that must be dispatching at all times
2. The minimum yearly online synchronous capacity, the represents the annual spinning reserve requirements that must be available at all times.

These values are implemented as additional constraints to the model while other assumptions remain the same as in the Limited Lifetime with Clean Energy Target policy.

The coal-fired generators continue to perform all their scheduled maintenance and refurbishment and therefore their thermal efficiencies and availabilities remain unchanged during their operation.

The inertia analysis was done on this model since there is a rapid uptake of renewable generation combined with a significant retirement of synchronous coal-fired generation.
2.1.8  10% probability-of-exceedance (10% POE) sensitivity

All the scenarios mentioned above are modelled using a 50% probability of exceedance peak demand. That means the likelihood that the peak demand forecast will be exceeded is 50%, or 5 years out of 10. In this sensitivity, we apply the 10% probability of exceedance (that is, the likelihood of exceeding the peak demand forecast is only 1 year out of 10) to all the previous modelling runs so as to determine what extra investment in capacity is needed to meet this higher peak demand.

The modelling for this sensitivity is done based on the following basis:

- For each scenario, the investment plan and capacity mix resulting from the 50% POE peak demand is kept unchanged.

- Using this capacity mix, the 10% POE median peak demand trace is used to run the model instead of the 50% POE.

- The resulting unserved energy under the 10% POE median peak demand is reported.

- The model adds the necessary generation capacity to meet the NEM's reliability standard of 0.002 per cent unserved energy per region per financial year, which means that out of 100,000 MWh of demand, no more than 2 MWh of outage would be allowed.
3. Market Modelling Assumptions

3.1 Demand

The NEM market model that is used in this study is based on 50% POE (median) peak demand and the medium economic growth demand forecasts available in the 2016 National Electricity Forecasting Report (NEFR). The use of the 50% POE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch. Post 2036 the energy and peak demand is assumed to remain flat. Demand was assumed to be flat because there is no way that reductions in demand due to efficiency will exceed increases due to new uses such as electric vehicles and electric space heating.

The underlying demand load profiles in the market model for each region are based on FY2011 actual half-hourly demand. This year is chosen as it reflects demand response to normal weather conditions and captures the observed demand coincidence between the States. In addition the FY2011 year is not greatly affected by generation that is embedded behind the meter (mainly in the form of rooftop PVs). This is important as Strategist models rooftop PV generation separately and therefore requires an underlying demand load shape that has not been distorted by large quantities of rooftop PV.

The peak demand and energy consumption forecasts that were originally developed by AEMO are adjusted by Jacobs by adding back AEMO’s forecast rooftop PV consumption. Some embedded generation, such as small scale cogeneration, is not included in the Strategist model, and the native load forecasts are adjusted by removing their expected contribution from the load. This typically represents less than 0.5% of regional energy consumption.

In each forecast year, Strategist scales and adjusts the regional base load profile to match the regional energy consumption and peak demand forecasts, after they have been adjusted by the above process. The regional energy historical and forecast consumption and historical and projected non-coincidence peak demand are shown in Figure 7 and Figure 8 respectively.

---

6 The 50% POE (probability of exceedance) for peak demand implies that there is a 50% probability the actual peak demand will not exceed the forecasted value.

7 The peak demand illustrated in the graph for every state is the “non-coincidence peak demand”, which means that it will not necessarily occur at the same time in every state.
Emissions mitigation policies and security of electricity supply

Figure 7: Base consumption growth historical and forecast sent out

Figure 8: Non coincidence peak demand historical and forecast
3.1.1 Impact of carbon price on demand

AEMO’s 2016 NEFR demand forecast is also adjusted by Jacobs in order to remove the impact of the assumed carbon price on energy demand. In AEMO’s 2016 NEFR a carbon price is assumed to be introduced in the NEM, commencing from $25/t CO$_2$-e and escalating linearly to $50/t CO$_2$-e by 2030, remaining flat thereafter. The introduction of future carbon pricing adds complexity to the demand forecasting as it is anticipated that there will be some demand response to the projected increase in electricity prices. The published forecasts already include assumptions on how demand may change in response to these higher electricity prices. AEMO has reported the long-run own price elasticity of electricity demand by region used to derive this anticipated demand response; AEMO’s latest values are summarised in Table 4. The own price elasticity represents the percentage change in demand expected for a 1% increase in electricity price.

Table 4: Assumed regional price elasticity of demand

<table>
<thead>
<tr>
<th>State</th>
<th>Price elasticity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>-0.37</td>
</tr>
<tr>
<td>VIC</td>
<td>-0.21</td>
</tr>
<tr>
<td>QLD</td>
<td>-0.32</td>
</tr>
<tr>
<td>SA</td>
<td>-0.23</td>
</tr>
<tr>
<td>TAS</td>
<td>-0.40</td>
</tr>
</tbody>
</table>

The magnitude of the expected electricity price increase depends on a number of assumptions, but the key driver is the difference between the assumed 0$/Mt CO$_2$ carbon price in the scenarios to be modelled and AEMO’s underlying carbon price. The process for incorporating changes to the level of demand as a result of the introduction of a carbon price is as follows:

- For each forecast year calculate the weighted average retail price across all customer segments using AEMO’s carbon price assumptions;
- For each forecast year calculate the weighted average retail price across all customer segments using the scenario carbon price assumptions;
- Calculate the percentage change in demand by applying the price elasticity of demand to the resulting movement in the retail price.
- Apply this percentage change to the adjusted demand (as described above in section 3.1).

With respect to peak demand, we assume the demand response is significantly lower and therefore the corresponding change in peak demand will be assumed to be only 25% that of the energy reduction or increase. This method allows for the observation that air-conditioning load which dominates the summer peak is not very price-sensitive (i.e. inelastic).

3.2 General assumptions

3.2.1 Structural assumptions

Structural assumptions that will be used in the modelling include:

- Capacity is installed to meet the reserve requirements as set by AEMO for the NEM in each region (maximum unserved energy allowed is 0.002% in each state per year).

---

8 Provided by AEMO as part of the study we undertook for the Climate Change Authority (see Jacobs (2016))
Emissions mitigation policies and security of electricity supply

- Annual demand shapes consistent with the relative growth in summer and winter peak demand. The native load shape is based on the FY2011 load profile for the NEM, with this being representative of a normal year in terms of weather patterns. The load profile presented to the thermal generation plant is modified by two factors: the small-scale and large-scale solar and wind resources added to the market since FY2011 and forecast by the modelling to be added; and the changing trend in growth of peak demand relative to average demand implicit in the forecasts.

3.2.2 Wind assumptions

Wind generation varies by location. Wind generation profiles in South Australia, Tasmania, Victoria and New South Wales are based on the observed aggregate wind power patterns for each region from the FY2016 financial year. They have been developed in each region bottom-up from historical half-hourly generation data. Wind generation profiles have also been developed for Queensland. Our approach is to use AEMO's projected hourly wind profiles developed for the 2016 NTNDP study\(^9\).

Some example aggregate monthly wind profiles for South Australia are presented below in Figure 9. The March profile is close to the annual average capacity factor of South Australian wind, whereas the August profile is an example of a month with high wind output.

Figure 9: South Australian wind profiles

3.2.3 Solar assumptions

Solar generation varies by location. Solar generation profiles in all of the NEM regions are based on AEMO’s projected solar profiles, developed for the 2016 NTNDP study\(^10\). The solar profile of South Australia for December and June is shown in Figure 10.

---


Figure 10: SA large-scale solar profiles

Note: We interpret the figure to represent the typical solar generation profile for a large scale system in South Australia. The hours in the June figure represent standard time and in the December figure daylight savings time.

3.2.4 Generator behaviour

Infrequently used peaking resources are bid near market price cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.

Units close or shut down under the following conditions:

- Units that recorded operating losses (disregarding their amortised capital costs) for greater than two years are mothballed for the period. If the losses extended beyond 10 years then the affected units are permanently shut down.

- Where a mine-mouth coal supply is exhausted and, based on general understanding of economic and physical constraints, appears unlikely to be extended.

- Generating units will be shut down sequentially in order of the magnitude of the loss per unit of capacity, and the model rerun to gauge how profitability of the remaining units changed. This process will be repeated until there is no unit recording operating losses.

In addition, the following assumptions are made about incumbent generators based on mothballing/retirement announcements to the market. We distinguish between generators currently withdrawn and those that have announced future withdrawals:

Withdrawn

- Pelican Point CCGT in South Australia currently has half of its capacity mothballed. It will be brought back into service in the model ahead of thermal new entry when profitable to do so.

- Swanbank E was mothballed in FY2015. It will be brought back into service in the model ahead of thermal new entry when profitable to do so.

- Engie permanently retired the Hazelwood Power Station (1600 MW) at the end of March 2017.

Announced Withdrawals

- Hydro Tasmania announced the eventual sale of Tamar Valley CCGT (208 MW) in 2015 but it has continued to operate as a backup to the hydro-electric system. Stanwell Corporation has advised AEMO that its Mackay GT (34 MW) will be permanently retired in the financial year 2020-21. We assume a retirement date of 1 July 2020 in the model.
• AGL originally announced the mothballing of its Torrens Island A (480 MW) power station in South Australia, slated to commence in April 2017. However, AGL has announced that this mothballing will not go ahead\(^1\), and as such we have restored the plant to full operation in the model.

• Smithfield Power Partnership advised AEMO that its New South Wales Smithfield cogeneration plant (171 MW) will be permanently retired in 2017. We have assumed in the model that the retirement occurs from 1 July 2017.

• AGL announced the retirement of its Liddell power station (2000 MW), located in New South Wales in 2022, which represents the end of its technical life. Jacobs has implemented this retirement in the modelling as announced.

### 3.2.5 Weighted average cost of capital

The weighted average cost of capital for coal under all scenarios is higher because of project risk. For example, a new coal power station would be expected to be of large capacity and take a long time to build. Even in a stable policy environment there is project risk related the size of the capacity addition relative to demand growth, technical risks incurred and the relative impact of future market outcomes on net project returns.

A different weighted average cost of capital is used in the BAU and in the policy scenarios in order to reflect the policy uncertainty in the BAU case. Feedback from ARENA and CEFC was supportive of this approach. The assumptions used for the weighted average cost of capital for the policy scenarios and the BAU cases are given in Table 5 and Table 6. All the WACC figures shown are pre-tax and adjusted for inflation. The basis of the gearing ratio is related to the perceived market and regulatory risk involved, which varies by technology, using information provided to the Finkel Review.

#### Table 5: Weighted average cost of capital in the policy scenarios

<table>
<thead>
<tr>
<th>Generator</th>
<th>Coal</th>
<th>Gas CCGT</th>
<th>Renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt to equity ratio</td>
<td>40:60</td>
<td>75:25</td>
<td>75:25</td>
</tr>
<tr>
<td>Cost of debt</td>
<td>5.3%</td>
<td>4.4%</td>
<td>4.4%</td>
</tr>
<tr>
<td>Cost of equity</td>
<td>13%</td>
<td>11%</td>
<td>11%</td>
</tr>
<tr>
<td>WACC</td>
<td>9.9%</td>
<td>6.1%</td>
<td>6.1%</td>
</tr>
</tbody>
</table>

#### Table 6: Weighted average cost of capital in the BAU scenario

<table>
<thead>
<tr>
<th>Generator</th>
<th>Coal</th>
<th>Gas CCGT</th>
<th>Renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt to equity ratio</td>
<td>40:60</td>
<td>75:25</td>
<td>75:25</td>
</tr>
<tr>
<td>Risk premium</td>
<td>5%</td>
<td>2%</td>
<td>1%</td>
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<tr>
<td>Cost of debt</td>
<td>5.3%</td>
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<td>4.4%</td>
</tr>
<tr>
<td>Cost of debt (including risk premium)</td>
<td>10.3%</td>
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<td>WACC</td>
<td>14.9%</td>
<td>8.1%</td>
<td>7.1%</td>
</tr>
</tbody>
</table>

3.2.6 Exchange rates and inflation

All values in the report are in June 2016 dollars unless otherwise specified.

The Consumer Price Index (CPI) is assumed to be 2.5% per annum in line with the mid-point of target rates by the Reserve Bank. The CPI is used to calculate real fuel prices. The wholesale market models are created in real dollar costs to show trends in real price terms.

The Australian dollar exchange rate in FY2016 is assumed to be US 73 cents and follows the Treasury projection for the medium term, as shown in Figure 11, and then decreases to the long term average rate of 0.73.

**Figure 11: Assumed Australian to United States dollar exchange rate**

![Graph showing exchange rate over years](image)

*Notes: The rise to 0.77 to 2018 follows the Treasury FY2016 Budget Projections (see Budget Paper No 1)*

3.2.7 Market structure

Existing market arrangements and regulations for the wholesale electricity markets are assumed to continue to the end of the study period. That is, the NEM remains a region-based energy only market.

We assume that the market is structured to remain largely competitive and continues the following arrangements:

- Victorian generators are not further aggregated
- The generators’ ownership structure in Queensland remains as public ownership
- The South Australia, Tasmanian and New South Wales assets continue under the current portfolio groupings

Arrangements for setting existing maximum price caps are assumed to continue to apply during the study period.

3.2.8 Baseline hydro-electric generator output

The total projected generation from renewables, primarily hydro-electric, before the renewable energy target was introduced in 2001 is 14,600 GWh.

Hydro-electric plants are set up in Strategist with fixed monthly generation volumes. Strategist dispatches the available energy to take the top off the load curve within the available capacity and energy. Any run-of-river
component is treated as a base load subtraction from the load profile. Table 7 and Table 8 show the monthly energy used in our model for the smaller hydro schemes.

Based on our market information we have produced monthly and annual energy values for the Snowy Hydro units. This information has been incorporated into the Strategist simulation as monthly energy generation.

The monthly minimum generation for Blowering and Guthega are based on market information acquired by Jacobs, largely driven by the irrigation requirements of these hydro systems. Table 7 shows the monthly generation for Murray, the Tumut power stations and for Hydro Tasmania. Hydro Tasmania's generation is set to the stated long-term average of 8,700 GWh.

**Table 7: Monthly energy for small hydro generators, GWh**

<table>
<thead>
<tr>
<th>Month</th>
<th>Barron</th>
<th>Hume</th>
<th>Kareeya</th>
<th>Blowering</th>
<th>Guthega</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>15.93</td>
<td>7.62</td>
<td>26.83</td>
<td>34.52</td>
<td>25.48</td>
</tr>
<tr>
<td>February</td>
<td>30.92</td>
<td>8.60</td>
<td>13.45</td>
<td>26.00</td>
<td>24.00</td>
</tr>
<tr>
<td>March</td>
<td>20.80</td>
<td>9.27</td>
<td>21.48</td>
<td>24.36</td>
<td>20.64</td>
</tr>
<tr>
<td>April</td>
<td>18.74</td>
<td>8.41</td>
<td>20.59</td>
<td>6.43</td>
<td>18.57</td>
</tr>
<tr>
<td>May</td>
<td>11.80</td>
<td>6.04</td>
<td>36.35</td>
<td>1.43</td>
<td>8.57</td>
</tr>
<tr>
<td>June</td>
<td>15.93</td>
<td>0.00</td>
<td>47.36</td>
<td>7.68</td>
<td>7.30</td>
</tr>
<tr>
<td>July</td>
<td>11.80</td>
<td>0.00</td>
<td>26.24</td>
<td>11.04</td>
<td>8.96</td>
</tr>
<tr>
<td>August</td>
<td>17.05</td>
<td>0.00</td>
<td>32.78</td>
<td>4.70</td>
<td>15.30</td>
</tr>
<tr>
<td>September</td>
<td>13.49</td>
<td>6.04</td>
<td>28.91</td>
<td>5.58</td>
<td>24.42</td>
</tr>
<tr>
<td>October</td>
<td>19.11</td>
<td>10.84</td>
<td>28.62</td>
<td>26.33</td>
<td>33.67</td>
</tr>
<tr>
<td>November</td>
<td>4.87</td>
<td>9.91</td>
<td>28.32</td>
<td>46.56</td>
<td>33.44</td>
</tr>
<tr>
<td>December</td>
<td>6.93</td>
<td>8.54</td>
<td>26.54</td>
<td>45.36</td>
<td>24.64</td>
</tr>
<tr>
<td>Total</td>
<td>187.38</td>
<td>75.26</td>
<td>337.46</td>
<td>240.00</td>
<td>244.98</td>
</tr>
</tbody>
</table>

**Table 8: Monthly energy for Victorian hydro units, GWh**

<table>
<thead>
<tr>
<th>Month</th>
<th>Dartmouth</th>
<th>Eldon 1-2</th>
<th>Kiewa/ McKay</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>26.78</td>
<td>42.37</td>
<td>8.27</td>
</tr>
<tr>
<td>February</td>
<td>23.56</td>
<td>33.25</td>
<td>7.23</td>
</tr>
<tr>
<td>March</td>
<td>21.42</td>
<td>31.32</td>
<td>7.23</td>
</tr>
<tr>
<td>April</td>
<td>10.71</td>
<td>27.54</td>
<td>12.40</td>
</tr>
<tr>
<td>May</td>
<td>5.36</td>
<td>1.57</td>
<td>24.80</td>
</tr>
<tr>
<td>June</td>
<td>5.36</td>
<td>0.00</td>
<td>33.07</td>
</tr>
<tr>
<td>July</td>
<td>8.57</td>
<td>1.13</td>
<td>36.17</td>
</tr>
<tr>
<td>August</td>
<td>10.71</td>
<td>4.22</td>
<td>43.40</td>
</tr>
<tr>
<td>September</td>
<td>10.71</td>
<td>13.17</td>
<td>47.54</td>
</tr>
<tr>
<td>October</td>
<td>12.85</td>
<td>14.14</td>
<td>51.67</td>
</tr>
<tr>
<td>November</td>
<td>21.42</td>
<td>14.30</td>
<td>44.44</td>
</tr>
<tr>
<td>December</td>
<td>23.56</td>
<td>22.56</td>
<td>28.94</td>
</tr>
<tr>
<td>Total</td>
<td>181.00</td>
<td>205.57</td>
<td>345.16</td>
</tr>
</tbody>
</table>
Table 7: Monthly energy limits for Snowy Hydro and Hydro Tasmania, GWh

<table>
<thead>
<tr>
<th>Month</th>
<th>Murray</th>
<th>Upper Tumut</th>
<th>Lower Tumut</th>
<th>Hydro Tasmania</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>114.74</td>
<td>134.21</td>
<td>46.20</td>
<td>716.53</td>
</tr>
<tr>
<td>February</td>
<td>178.19</td>
<td>192.44</td>
<td>43.67</td>
<td>508.08</td>
</tr>
<tr>
<td>March</td>
<td>172.03</td>
<td>148.78</td>
<td>43.84</td>
<td>677.22</td>
</tr>
<tr>
<td>April</td>
<td>149.48</td>
<td>121.72</td>
<td>45.78</td>
<td>708.18</td>
</tr>
<tr>
<td>May</td>
<td>166.52</td>
<td>164.12</td>
<td>51.16</td>
<td>783.00</td>
</tr>
<tr>
<td>June</td>
<td>195.22</td>
<td>196.68</td>
<td>39.57</td>
<td>957.00</td>
</tr>
<tr>
<td>July</td>
<td>238.83</td>
<td>261.92</td>
<td>44.58</td>
<td>783.01</td>
</tr>
<tr>
<td>August</td>
<td>207.94</td>
<td>153.79</td>
<td>47.54</td>
<td>696.00</td>
</tr>
<tr>
<td>September</td>
<td>42.00</td>
<td>8.84</td>
<td>47.69</td>
<td>870.00</td>
</tr>
<tr>
<td>October</td>
<td>125.00</td>
<td>10.00</td>
<td>43.60</td>
<td>835.53</td>
</tr>
<tr>
<td>November</td>
<td>91.60</td>
<td>115.64</td>
<td>46.88</td>
<td>568.80</td>
</tr>
<tr>
<td>December</td>
<td>114.39</td>
<td>121.64</td>
<td>44.50</td>
<td>596.67</td>
</tr>
<tr>
<td>Total</td>
<td>1795.93</td>
<td>1629.79</td>
<td>545.00</td>
<td>8700.00</td>
</tr>
</tbody>
</table>

Source: Jacobs based on market data published by AEMO

3.3 Technology costs

3.3.1 Existing generators

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operation costs. The indicative variable costs for various types of existing thermal plants are shown in Table 8. For brown coal in Victoria, where the open-cut mine is owned by the generator, the variable costs also include the net present value of changes in future capital expenditure for the mine. This makes up about 50% of the variable cost. The same principle is used for the Millmerran and Kogan Creek black-coal-fired generators, which are also co-located with mines in Queensland.

Fixed operating cost data are based on available data on operating cost for like plant and data published by the market operators for their planning processes. For the NEM, fixed operating costs are based on publicly available data from AEMO. Fixed operating cost data change over time in accordance with assumptions on projections of growth in wage rates, which are sourced from Treasury budget projections.

Thermal power plants are modelled with planned and forced outages with overall availability consistent with current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%. Indicative average variable costs for existing thermal plants are shown in Table 10, while more details regarding the technology costs and performance of the plants are given in Appendix C.

---

12 Jacobs uses the Australian Energy Market Operator's publicly available data to develop fixed costs for conventional coal and gas plant as well as renewable energy technologies. This is located at: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions. Jacobs' database was used as the source for avoidable operating and maintenance costs, which are employed in the decision making process for plant mothballing and retirement.
Table 8: Indicative average variable costs for existing thermal plant ($June 2016)\textsuperscript{13}

<table>
<thead>
<tr>
<th>Technology</th>
<th>Variable Cost /MWh</th>
<th>Technology</th>
<th>Variable Cost /MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brown Coal – Vic</td>
<td>7 – 10</td>
<td>Black Coal – NSW</td>
<td>20 - 23</td>
</tr>
<tr>
<td>CCGT – Vic</td>
<td>54 – 151</td>
<td>Black Coal - Qld</td>
<td>9 - 31</td>
</tr>
<tr>
<td>CCGT – SA</td>
<td>41 – 65</td>
<td>CCGT - Qld</td>
<td>25 – 57</td>
</tr>
<tr>
<td>Oil – SA</td>
<td>199 – 320</td>
<td>Oil – Qld</td>
<td>245 – 299</td>
</tr>
<tr>
<td>Open cycle gas – SA</td>
<td>115 – 183</td>
<td>Black Coal - WA</td>
<td>32 – 43</td>
</tr>
</tbody>
</table>

Source: Jacobs’ data base of generation costs, which in turn is based on market data published by AEMO, annual reports of generators and fuel suppliers, ASX announcements and other media releases.

3.3.2 New entrant generators: cost and availability

The model selects new capacity from a range of currently available fossil fuel and renewable technologies that could be considered in the NEM. Parameters for technologies that are not presently commercially available are included where an estimate can be made of their performance and costs for use in the modelling. In each scenario the least cost mix of plant is dispatched to meet demand, fuel and capital costs, and any policy constraints.

Hence:

- Technologies that are included as new plant options are wind, solar PV, solar thermal, hydro-electric systems, biomass-based generation, simple and combined cycle gas turbines, super and ultra-supercritical coal fired steam turbines, integrated gasification combined cycle plant with carbon capture and storage (utilising coal as a fuel), geothermal, battery storage and pumped storage.

- Technologies that are excluded are nuclear generation, tidal and wave technologies.

New entrant technology costs are derived at a-point-in-time (generally an estimate of current costs) and future costs are handled within the modelling using learning curves and adjustments for changes in exchange rates.

For gas turbine based plants and conventional Rankine cycle plants (including sub-critical, supercritical and ultra-supercritical, and biomass), Jacobs uses the capital cost estimating tool within the Thermoflow suite of software. This model estimates engineering, procurement and capital (EPC) capital costs\textsuperscript{14} based on technical configurations of each plant that is considered to be appropriate for Australian conditions and fuels. Jacobs applies local factors (such as the unit sizing, suitability for Australia’s climate and fuel alternatives) for the configuration of the plants and for regional factors (such as labour and other costs for Australian construction environments). These factors are based on our experience and judgement.

The cost estimates are refined using adjustment factors where considered appropriate based on market soundings and information from other projects (such as overseas).

In addition to the EPC costs, allowances have been made for coal drying plant costs, connection costs (for electricity and gas where applicable) and owner’s costs. Interest during construction costs are handled separately in the modelling.

\textsuperscript{13} The variable cost of gas based peaking plant assumes that the fixed cost of pipelines and processing assets are converted into a variable cost to reflect opportunity cost of using assets at low levels of utilisation and to enable bids for these plants to be set at a rate that will recover their fixed costs for the limited time they are typically dispatched.

\textsuperscript{14} Engineering, procurement, construction (EPC) capital costs refer to the expected capital cost when a power plant construction project is carried out by EPC contractors, which is typically engaged by the project owner. These companies carry out the detailed engineering design of the power plant, procure all required materials and equipment, and then carry out the construction, delivering a functioning power plant to the owner.
Wind and PV costs are updated using observed recent costs for Australia.

Solar thermal and hydro costs are subject to limited new data in the Australian context and remain as assumed in previous Jacobs’ studies.

The costs were reviewed by CSIRO, AEMO and ARENA and adjustments were made to the cost estimates to reflect their comments.

Current estimates for capital costs of new technologies are shown in Appendix D. These are based on 0.73 USD exchange rate.

### 3.3.3 Storage costs

Small-scale storage costs are based on the recent Tesla Powerwall 2 battery release cost, while the learning rates are taken from the CSIRO study. Our understanding is that the technology underpinning the Powerwall 2 product is scalable, and therefore for the large-scale costs we propose to apply a further 10% discount relative to the small-scale cost, to represent economies of scale that should be achievable for a larger system size.

#### Table 9: Technology cost assumptions for battery component of a storage system by scale

<table>
<thead>
<tr>
<th>Technology</th>
<th>$/kWh nominal capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small-scale storage</td>
<td>593</td>
</tr>
<tr>
<td>Large-scale storage¹⁶</td>
<td>533</td>
</tr>
</tbody>
</table>

Source: Jacobs

In deriving the above technology costs the following assumptions were used:

- Battery type: lithium-ion
- Retail price: 8,000 $AUD
- Nominal Storage: 13.5 kWh
- Power: 5 kW steady, 7 kW peak
- Total warranted kWh: 37,800
- Maximum guaranteed life: 10 years
- Roundtrip efficiency: 90%

The price includes a battery inverter and can be retrofitted to existing systems, but does not include installation costs.

Figure 12 shows how storage costs are projected to decline over the next 20 years.

---


¹⁶ Large-scale storage refers to system sizes 1 MW and above.
3.3.4 Coal prices

Black coal prices on world markets have recently fallen after a prolonged period of high prices. Based on projections of coal price published by the IEA (2016) coal prices on export markets are likely to stabilise around current levels or slightly higher than current levels in the long term. This will impact on domestic coal prices as these generally reflect export parity prices with a discount for higher ash levels and lower fuel contents. Coal prices will generally impact on the power stations not at mine-mouth (NSW coal plant and central Queensland coal plant), or those associated with a mine that also exports coal. This includes all coal-fired generators in NSW and Queensland, with the exception of Millmerran and Kogan Creek.

Brown coal prices are insensitive to movements in global coal markets because brown coal is not exported. Brown coal prices are assumed to remain flat in real terms over the forecast period. Brown coal costs are typically less than 50 c/GJ.

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17 International Energy Agency (2016), World Energy Outlook: 2016. The projections in this study are based on the outcomes of the new policies scenario contained in the report.
Figure 13: Coal prices for major coal-fired power stations in the NEM

Source: Jacobs

### 3.3.5 Gas prices

Gas price forecasts for the NEM up to year 2023 are derived based on projected demand-supply balance in Eastern Australia using our proprietary model, MMAGas (Market Model Australia – Gas). From year 2024 and onwards we have applied the projected world gas price growth under the new policy scenario published by the IEA (2016).¹⁸

The MMAGas model intends to replicate the essential features of Australian wholesale gas markets:

- A limited number of gas producers
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Domestic market growth driven by gas-fired generation and large industrial projects.
- Strong influence of LNG exports on supply availability for the domestic market.

The gas market model assumes that the $A is initially equal to US73c ¹⁹ and follows the Treasury projection thereafter (see Figure 11).

---

¹⁸ These projected trends in the long term gas price follows the projected world gas price under the new policy scenario published by the IEA. See IEA (2016), *World Energy Outlook: 2016*.

¹⁹ A decrease in the $A would increase gas prices
Emissions mitigation policies and security of electricity supply

The applicable wholesale average city gate gas prices that were used in the modelling are shown in Figure 14. The model is structured around some fundamental principles:

- With the export market being the predominant market from FY2017, gas prices converge to between the export parity and import parity levels. The degree to which prices are above export parity levels depends on the degree of competition in the domestic gas market or the level of any constraint on developing new gas supplies.

- Export parity levels are set at the LNG net back prices (that is, world prices for LNG - assumed to be set at export prices for natural gas in major markets - after shipping, processing and handling costs are deducted). Shipping and other costs are based on the historical differential between cost insurance and freight (c.i.f.) prices in Japan and free (f.o.b.) on board (f.o.b.) export prices.

- Import prices are set at the energy equivalent of oil or liquid fuels, being the main substitute for gas in most end-uses.

For the period to 2023 we have used our medium gas price projections, which assume gas prices rise above world parity levels over the period to FY2019 due to a shortage of gas to meet contracted commitments for LNG. Thereafter prices fall to world parity level.

Prices are affected by the following factors:

- Over the next few years, supply of gas will remain tight as LNG trains come on line and gas is required to meet export commitments.

- The tightness of supply is not likely to dissipate until 2019 at the earliest due to time required to attain approval and develop additional coal seam gas wells.

- Thereafter gas prices are assumed to continue rising, reflecting an international level of effort on emissions abatement.

Figure 14: Wholesale new contract city gate gas prices for electricity market modelling ($June 2016)

Source: Jacobs
3.3.6  **Renewable long run marginal costs**

Technical and cost assumptions for new renewable technologies are highlighted in Appendix C. However, these are average estimates and there will be differences as more of these technologies are deployed due to differences in transmission connection costs, fuel costs (for biomass), insolation levels (for solar projects) and wind regimes (for wind projects).

A critical requirement is the database of potential renewable energy projects. Jacobs has developed a database which includes existing, committed, and prospective projects including some allowance for generic projects based on projections by industry organisations. Figure 15 shows some indicative cumulative renewable energy supply curves for years 2020, 2030, 2040 and 2050 developed from the database for all proposed and generic renewable plants. The supply curve for 2020 includes the LRMC of the renewable plants in 2020, while the supply curves in 2030 the LRMC of these plants in 2030 (which are reduced due to their individual learning rates) and so on.

Figure 15: Renewable energy supply curves for years 2017, 2020, 2025 and 2030 ($ June 2016)

![Graph showing renewable energy supply curves](image)

Source: Jacobs

The capacity factors for these plants vary significantly from project to project. Some indicative ranges for the wind and solar generic projects are given in Table 10 below.

**Table 10: Indicative capacity factors by technology and region**

<table>
<thead>
<tr>
<th></th>
<th>Victoria</th>
<th>New South Wales</th>
<th>Tasmania</th>
<th>South Australia</th>
<th>Queensland</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Wind</strong></td>
<td>34-40%</td>
<td>34-38%</td>
<td>34-43%</td>
<td>36-43%</td>
<td>29-34%</td>
</tr>
<tr>
<td><strong>Large scale PV</strong></td>
<td>22-26%</td>
<td>22-28%</td>
<td>20-23%</td>
<td>23-27%</td>
<td>23-29%</td>
</tr>
</tbody>
</table>

Note: There are some existing, committed and proposed projects in the database with capacity factors outside the indicative ranges shown in the table.

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20 The capacity factors are AC and include fixed and tracking PV systems
3.3.7 Small-scale PV uptake

For the projection of small scale PVs, Jacobs has used AEMO’s medium trajectory of rooftop PV uptake from the National Electricity Forecasting report (NEFR) as shown in Figure 16. That includes rooftop PV with and without battery storage.

Figure 16: Rooftop PV uptake by region

Source: AEMO, NEFR 2016

3.4 Interconnection and losses

The model begins with a representation of the existing network capacity. New interregional capacity competes with new generation capacity and is built on a least-cost basis.

Assumptions on initial interconnect limits are shown in Table 11. We have retained a Snowy zone in our Strategist model to better represent the impact of intra-regional constraints on each side of the Victoria/NSW border.
Table 11: Interconnection limits – based on maximum recorded flows

<table>
<thead>
<tr>
<th>From</th>
<th>To</th>
<th>Capacity</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Victoria</td>
<td>Tasmania</td>
<td>480 MW</td>
<td>480 MW</td>
</tr>
<tr>
<td>Tasmania</td>
<td>Victoria</td>
<td>600 MW</td>
<td>600 MW</td>
</tr>
<tr>
<td>Victoria</td>
<td>South Australia</td>
<td>630 MW</td>
<td>630 MW</td>
</tr>
<tr>
<td>South Australia</td>
<td>Victoria</td>
<td>630 MW</td>
<td>630 MW</td>
</tr>
<tr>
<td>South Australia</td>
<td>Redcliffs</td>
<td>135 MW</td>
<td>135 MW</td>
</tr>
<tr>
<td>Redcliffs</td>
<td>South Australia</td>
<td>220 MW</td>
<td>220 MW</td>
</tr>
<tr>
<td>Victoria</td>
<td>Snowy</td>
<td>1,300 MW</td>
<td>1,300 MW</td>
</tr>
<tr>
<td>Snowy</td>
<td>Victoria</td>
<td>1,900 MW</td>
<td>1,900 MW</td>
</tr>
<tr>
<td>Snowy</td>
<td>NSW</td>
<td>3,559 MW</td>
<td>3,117 MW</td>
</tr>
<tr>
<td>NSW</td>
<td>Snowy</td>
<td>1,150 MW</td>
<td>1,150 MW</td>
</tr>
<tr>
<td>NSW</td>
<td>South Queensland</td>
<td>120 MW</td>
<td>120 MW</td>
</tr>
<tr>
<td>South Queensland</td>
<td>NSW</td>
<td>180 MW</td>
<td>120 MW</td>
</tr>
<tr>
<td>NSW</td>
<td>Tarong</td>
<td>589 MW</td>
<td>589 MW</td>
</tr>
<tr>
<td>Tarong</td>
<td>NSW</td>
<td>1,078 MW</td>
<td>1,078 MW</td>
</tr>
</tbody>
</table>

Source: Combination of ESOO and historical market data

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO 26 May 2016 Report “Regions and Marginal Loss Factors: FY 2016-17”.

The loss factor equations published by AEMO are converted to losses by integrating the equation $(Loss \ factor - 1)$ with respect to the interconnector flow. This leaves an unspecified constant, and Jacobs’ approach is to avoid negative losses by shifting the quadratic loss equation so that the minimum of the quadratic equation is zero, rather than a negative number. This criterion provides enough information to define the constant term of the quadratic equation.

Benefits due to lower losses across the inter-regional interconnects are modelled directly in the Strategist model using equations that mimic the transfer equations used in AEMO dispatch algorithms.

Intra-regional losses are applied as detailed in the AEMO report entitled “Regions and Marginal Loss Factors: FY 2015-16 V2.0”.

The long-term trend of marginal loss factors is extrapolated for two more years by using a linear trend, and then held at that extrapolated value thereafter.

Generalised estimates of interconnector expansion sizes and costs have been derived from AEMO’s National Transmission Network Development Plan 2015.

### 3.5 Federal and State policies

The following policies are considered for this work.
3.5.1 National policies

The Renewable Energy Target

The large-scale renewable energy target (LRET) is a legislated requirement on electricity retailers to source a given proportion of specified electricity sales from renewable generation sources, ultimately creating material change in the Australian technology mix towards renewable alternatives. The target mandates that 33,000 GWh must be derived from eligible renewable sources by 2020 and maintained through to 2030. Emissions Intensive Trade Exposed industry are exempt from paying the liabilities of the large-scale renewable target.

The large-scale energy renewable target works by creating a market for additional renewable electricity that supports investment in new renewable generation capacity. It places a legal obligation on entities that purchase wholesale electricity (mainly electricity retailers) to surrender a certain number of certificates to the regulator each year. These certificates are generated by accredited renewable generators. Each certificate represents one megawatt hour (MWh) of additional renewable energy for compliance purposes; the certificates are tradable and can be ‘banked’ in unlimited quantities for use in later compliance years. Liable entities can also effectively ‘borrow’ from future surrenders (this is limited to 10% of an entity’s annual liability).

Another scheme supporting smaller scale renewable generation options has also been enacted, called the Small-scale Renewable Energy Scheme (SRES).

The costs of sourcing renewable generation under the LRET and SRES are met by an additional cost added to retail electricity bills. The scheme is administered by the Clean Energy Regulator (CER).

The Emissions Reduction Fund

The Emissions Reduction Fund (ERF) purchases accredited emissions reductions. Under Australia’s commitment to the Kyoto Protocol[^21], Australia must reduce its greenhouse gas emissions to 5% below 2000 levels by 2020. The ERF is administered by enabling creation of Australian Carbon Credit Units (ACCUs) through a reverse auction or tender process.

Sectoral coverage of the ERF is wider than the energy sector, and can include agricultural and forestry activities under the Carbon Farming Initiative, as well as avoided emissions from landfill. Other emissions reduction activity may include industrial and commercial energy efficiency and emissions avoidance projects. It is unlikely under current parameters and allocated budgets to encourage uptake of large-scale low emissions generation options. Therefore the ERF is not considered in the modelling.

Another element of the policy is the safeguard mechanism which started on 1 July 2016. The safeguard mechanism applies a baseline across the electricity sector. If the sectoral-baseline is exceeded then baselines for individual generators apply. The sectoral baseline is set at the high point of sectoral emissions over the period 2009-10 to 2013-14.

3.5.2 State and territory policies

Feed in tariffs

Feed-in tariffs are equivalent to payments for exported electricity. Feed-in tariff schemes have been scaled back in most jurisdictions so that the value of exported energy does not provide a significant incentive to increase uptake of solar PV systems. All States now only mandate fair and reasonable tariffs to apply to exports, reflecting the value of equivalent wholesale prices. This approach will be assumed in this study.

ACT renewable target

The ACT recently announced that it would extend its existing renewable energy target from 90% to 100% by 2020. The target is achieved by enabling large scale solar and wind auctions which enable the territory to economically undertake power purchase contracts with renewable energy generators in the ACT and other states to produce an equivalent amount of power to what is used within the ACT. This is modelled by Jacobs as a small increase to the RET.

Victorian renewable target

The Victorian government has announced an initiative to purchase renewable energy certificates from new renewable energy projects in Victoria to offset emissions associated with its own energy use. This initiative is expected to encourage around 100 MW of wind capacity to be built in the state. However, as the certificates to be purchased will not be additional to the large-scale renewable energy target and as Victoria is likely to achieve in excess of this in the next five years under Business as Usual conditions, this initiative is not explicitly considered in this analysis.

The Victorian Government recently announced it will set a renewable energy target of 25 per cent by 2020 and 40 per cent by 2025. This is translated to approximately 1,500 MW of new large-scale renewable capacity to be installed in the state by 2020 and around 5,400 MW by 2025. The target will be met by a competitive reverse auction scheme and the capacity after 2020 will be additional to the large-scale renewable energy target national target. At the time of modelling, the Victorian renewable target had not been legislated and therefore is not included in this modelling.

Queensland renewable target

The Queensland government has announced support for 60 MW of large scale solar PV, whilst Ergon Energy is concurrently running an Expression of Interest for 150 MW of large scale renewable energy. These projects are treated as a Queensland specific increase to the large-scale renewable energy target in the modelling. It is noted that any projects built under these support measures will still generate LGCs and contribute to the large-scale renewable energy target.

The Queensland government has announced its commitment to achieve a 50 per cent renewable energy target by 2030 and launched an independent Renewable Energy Expert Panel to consider a credible pathway to achieving this target. The panel suggested implementing a competitive reverse auction process for an indicative target of up to 400 MW of large-scale renewable capacity prior to 2020 and up to 5,500 MW between 2020 and 2030. The Queensland renewable target has not been legislated yet and therefore is not included in this modelling.

State and Territory energy efficiency policies

States and territories in Australia have implemented energy efficiency policies. Where possible, these policies have been included in the baseline energy demand projections.
4. Comparative analysis

4.1 Key similarities and differences

The purpose of this study was to assess the impacts of firm policy prescriptions when compared with the current environment of uncertainty over the direction for policies for mitigating emissions in the power generation sector.

Under the Business as Usual scenario, wholesale electricity prices and the economic costs of supplying electricity is elevated due to the lower availabilities of the coal plant and the higher risk premium due to policy uncertainty that applies to new plant.

Economic (resource) costs under the policy scenarios are generally higher than for the Business as Usual scenario. The lowest cost options for the policy scenarios are for an EIS scheme, followed closely by the CET scheme. Costs are increased where a limited lifespan is applied to existing generators, as this brings forward the cost of investment in new plant and increases the level of that investment. Limiting lifetimes also increase the need for new dispatchable plant – typically higher cost gas-fired plants - that can meet demand in periods when renewable energy is not generating.

In all scenarios, the level of coal-fired generation diminishes over the modelling period. The extent and pace of the fall in generation depends on the extent of restrictions on lifespan and the interaction of the policy measure with wholesale prices.

The level of renewable generation increases under all scenarios. Even without additional policy support under the BAU scenario, declining assumed costs means that it is least cost for some level of renewable generation to enter the market.

However, some form of dispatchable generation is required from around 2030 onwards to fill the gap in meeting demand when renewable sources are not generating. This role is undertaken by gas-fired generation when the life of coal plant is limited but is filled largely by existing coal plant otherwise. There is some role for energy storage capability to fulfil this function but the magnitude of the requirement for dispatchable forms of generation and the assumed cost of energy storage limits the uptake of this option.

Although emissions are reduced under all scenarios, the 2030 target is not met without some additional policy support. Limiting the life of the coal plants is not sufficient to meet the target to 2030, but the large amount of retirements post 2030 do mean that the trajectory post 2030 is met. Hence, additional policy measures are required to meet targets to 2030.

The 2030 target is met under both the CET and EIS policies.

Wholesale prices are similar across the scenarios except for the CET and EIS scenarios, where the effective subsidies provided mean that wholesale prices are lower particularly for the CET scenario.

Retail prices are lower under the CET and EIS than all other scenarios even when taking into account the compliance costs of the CET scheme.

4.2 Generation and capacity

The generation mix across the scenarios is impacted by the assumed lifespan for generating plant and the extent of support provided to low emissions technologies under the policy measures.

Limiting the lifetimes of coal-fired plants affects the extent of uptake of gas-fired generation and renewable energy generation (compare Figure 17 with Figure 18). Coal-fired generation is generally highest under the BAU scenario until around 2040, when the bulk of the fleet reaches 60 years of age and the decision is made to retire them rather than continuing to refurbish the plant. The level of coal fired generation across the scenarios in
which the lifetime of coal-fired plant is limited to 50 years is fairly similar, showing a sharp reduction of
generation levels after 2030 when a large part of the fleet reaches 50 years. Under the CET and EIS scenarios
where a limited lifetime is not imposed, coal generation is maintained and has a more gradual decline as the
existing plants undertake the task of meeting demand when renewable energy generation is not available.

Levels of gas-fired generation are dependent on the level of retirement of coal plants. When coal plants retire,
gas-fired generation is required to meet the gap between demand and available renewable energy generation.
In the cases where the coal fleet is retired at 50 years of operation, the level of gas-fired generation trebles from
2035 onwards. Where there is no limited lifetime applied to coal plant, the level of gas fired generation is stable
across the modelling period and the existing coal fleet is used to meet demand when there is not enough
renewable energy generation.

Renewable energy generation expands across all scenarios, with the rate of expansion depending on the level
of policy support. The highest level of growth occurs under a CET and EIS schemes. Interestingly, when there
is only a Limited Lifetime policy with no restrictions on investment in new coal plant, a combination of new gas
and new renewable plant is chosen indicating the increasing competitiveness of renewable energy options
versus coal.

Energy storage (usually associated with solar PV) capacity also increases especially after 2035. The role of
energy storage in the modelling appears limited to energy arbitrage or peak shaving role. To meet the bigger
role for plant to fill in the gap not met by renewable energy generation would require significantly more
renewable energy capacity and significantly more storage capacity making it uneconomic compared with
conventional alternatives for the emissions target examined in this study.

**Figure 17: NEM coal power station closures**

Note: All the cases including the Limited Lifetime policy have the same coal closure schedule.
4.3 Emissions

Emissions are projected to fall across all scenarios with the rate of the fall dependent on the policy approach. Emissions fall in the BAU but by not enough to meet the annual emissions targets. Just requiring plants to close at 50 years of age does not meet the annual targets until after 2030 when a large portion of the coal fleet retires.

By design, the CET and EIS schemes meet the required annual targets across the entire period to 2030. However, combining these policies with limited lifetime for generating plant means there is an overachievement of the trajectory from around 2032. This effectively may undermine the operation of the CET or EIS scheme because there is a prolonged period when these schemes are not required to meet the emissions target (seen by the finding that certificates prices under these schemes are zero from 2032 onwards).
Figure 19: NEM Emissions, all scenarios

Figure 20: NEM Emissions intensity, all scenarios
4.4 Prices

Wholesale prices are projected to be similar across the Business as Usual and scenarios with a limited lifetime imposed on generating plant. Under these scenarios wholesale electricity prices rise gradually from 2020 onwards plateauing at around $90/MWh.

Wholesale prices are lower under the CET and EIS scenarios (without limited lifetime imposed). Both schemes provide an additional revenue stream for low emissions generation to enter and this reduces prices either by the greater penetration of plant with zero dispatch costs or because gas plant reduce their dispatch bid to reflect the value of earning certificates. Prices are lowest for the CET because there is no direct penalty applied to coal-fired generators as under the EIS, which also means that there is no distinction between black coal and brown coal under the CET as there is under the EIS. Further, under an EIS, the revenue earned by gas-fired generators through certificates reduces over time as the sectoral baseline reduces.

Retail price trends follow trends in wholesale prices. Retail prices rise in line with the increase in wholesale prices. Retail prices for a CET and EIS scheme (without any limited lifetime applied on plant) are lower than for the other scenarios but the gap (evident in the wholesale prices) between the CET and EIS schemes is reduced as the cost of certificates are added onto to retail prices under the CET scheme22. Residential retail prices for these two schemes are on average around 7% to 10% lower than for other scenarios. The retail price for the CET is 3 per cent lower than the EIS scheme over the whole modelling period under the assumptions used in this modelling. Industrial retail prices for the CET and EIS schemes are also lower than in all other schemes (11% to 17% lower on average) with prices under the CET scheme being lower than the EIS scheme on average over the 33 year period.

22 As certificates are traded amongst generators in an EIS scheme, the certificate cost is not assumed to be passed onto to the retail prices except so far as they impact on wholesale price.
Retail prices for the CET scheme are less than 3% lower than under an EIS scheme°.

Figure 22: NEM wholesale prices, all scenarios

Figure 23: NEM residential retail tariffs, all scenarios

° This holds true for the assumed scheme designs used in the modelling.
Emissions mitigation policies and security of electricity supply

Figure 24: NEM industrial retail tariffs, all scenarios

Figure 25: Certificate prices
4.5 Resource costs

Differences in resource costs compared to the BAU scenario are shown in Figure 26. All policy scenarios have higher resource costs than for the BAU due principally to either higher levels of gas-fired generation (hence higher fuel costs) or additional capital expenditure on new plant, or both.

Of the policy scenarios, the EIS scheme has the lowest resource costs. The resource costs to 2050 under this scenario are around $3.5 billion higher over 33 years than in the BAU scenario when using a 7% discount rate. Resource costs are slightly higher under a CET scheme due principally to more investment in new plant, estimated to be around $5 billion when using a 7% discount rate. For all other policy scenarios, the difference is greater than $12 billion.

Figure 26: Resource costs relative to the Business as Usual, all scenarios (2017-2050)

Note: the costs shown in this chart are the difference in present value in resource costs to the BAU scenario over the period to 2050, calculated using a discount rate of 7%.
5. Business as Usual

5.1 Scenario description

The Business as Usual scenario is a world where uncertainty continues over the future course of emissions reduction policy. With this continued uncertainty, investors face high risks in investing in new emissions intensive plants, with the perception that such new plant could become stranded assets if any mitigation policy was implemented. Further, maintenance in existing high emissions plant is also affected with plant owners only carrying out major maintenance or refurbishment if a quick payback can be ensured on the cost upgrades and refurbishment.

Because of the ongoing uncertainty, generating units are retired either if they become uneconomic or at the end of their technical life, deemed to be at the end of 60 years of operation.

5.2 Key findings

The findings of the Business as Usual scenario can be summarised as follows:

- Coal-fired generation reduces gradually to 2040 either because of announced retirements, deterioration of performance (reduced availability), or plant reaching the end of their operating lives. After 2040, there is a large drop in coal-fired generation as the bulk of plant reach 60 years of operating life.

- The reduction in coal-fired generation is replaced by additional gas-fired generation, additional wind and solar PV generation, and solar PV with battery storage. In the long term, gas generation triples reaching 29% of total generation by 2050. The level of renewable generation also increases to reach (with the inclusion of roof top PV) around 52% of total generation by 2050, with around 40% being variable wind and solar generation (without storage).

- Wholesale prices remain relatively steady at around $70/MWh to $80/MWh until around 2030, when average prices jump by around $10/MWh, in line with the long run marginal cost of efficient gas-fired generation and or renewable energy with storage. As a result retail prices also jump by around the same level.

- Reflecting the change in composition of generation, the level of emissions continues to fall but by not enough to achieve the 28% target reduction in 2030. The emissions intensity of electricity generation also continues to fall.

Under the assumptions behind this scenario, the trends currently seen in the electricity industry continue. The proportion of coal-fired generation continues to decline and the proportion of gas-fired and renewable generation increases especially after 2030. And wholesale prices remain around current levels, with prices projected to remain above the historical average price of around $50/MWh.\(^ {24}\)

5.3 Generation and capacity

The projected trends in generation are illustrated in Figure 27. The level of coal generation falls immediately with the retirement of Hazelwood, and again when Liddell Power Station retires in 2022. Other coal plants do increase their level of generation after these plants retire but only partially replace the generation from the two retired plants. Coal generation reduces gradually to 2032 due to declining availability across the coal fleet. Some coal plants are predicted to retire from 2032 to 2035 after reaching the end of their operating life. Coal plant retirements start to accelerate after 2038, when the subcritical coal plants start reaching the end of their operating life (see Figure 29).

\(^ {24}\) That’s the mean price across the NEM regions for the period May 2005 to December 2016.
Up until 2020, investment in new plant is solely in renewable energy, with some 7 GW of capacity in utility scale renewable energy commencing operation as a result of support of the LRET and other measures. New renewable capacity almost doubles by 2040 and by 2050 there is additional capacity of utility scale renewable plant of around 20 GW, with new capacity after 2020 shared roughly equally between solar PV (with and without storage) and wind generation.

There is also investment in new gas-fired capacity with some investment required almost immediately after the retirement of Liddell. Investment in gas-plant, particularly open cycle plant, is correlated strongly with retirement of coal-fired generation units, with uptake particularly prevalent after 2040.

The finding that there is investment in a mix of renewable and gas plant reflects two factors. First, the assumed continuing decline in installed cost of utility scale renewable generation and second the expected gas price, which is assumed to rise from current elevated levels. However, despite these trends there is still need for new gas plant in the long term due to the need for dispatchable forms of generation (where gas-fired generation competes with renewables with storage options).

Figure 27: Generation mix, BAU
Figure 28: Cumulative new capacity by technology type, BAU

Figure 29: Cumulative retired capacity by technology type, BAU
5.4 Emissions

Emissions are projected to decline over the modelling period. There is a sharp reduction in emissions to 2020, brought about by the additional renewable energy generation entering the market under the LRET scheme and the retirement of Hazelwood, which had the highest emissions intensity of any plant in the NEM. There is a small drop in emissions from 2022 as Liddell also retires. From there, emissions decline gradually as the availabilities of the coal fleet reduces. There are large step drops in emissions from 2032 associated with further retirement of coal-fired generators and the increasing penetration of renewable and gas-fired generation.

Although emissions fall they do not fall enough to meet the 28% target reduction nor is the assumed longer term trajectory met.

Figure 30: NEM Emissions and emissions targets, BAU

Figure 31: NEM Emissions intensity, BAU
5.5 Prices

Wholesale electricity prices are expected to remain around current levels. Prices are expected to increase in 2018 due to this being the first full year without Hazelwood. Prices then fall to 2020 as new renewable capacity enters the market. Thereafter, prices gradually increase in line with assumed increases in gas prices and the fall off in availability of the coal-fired generators.

Although Queensland starts with the highest prices, it ends up having the lowest price due to the availability of low cost generating plant and the increased level of penetration of solar PV (Queensland has the highest proportion of solar PV plant), which depresses daytime prices.

Prices are generally higher in Victoria, particularly after the availability of some coal-fired power units reduces, which means that gas-fired plant set the price more often in that State.

Retail price trends follow the trends in wholesale prices, however the relative price movements are muted since the wholesale price only comprises around 30% of the retail price. In line with wholesale prices, retail prices fall over the period from 2018 to 2020. Prices then recover to be around current levels in the late 2020s. Retail prices for residential customers average 31 c/kWh in the period from 2020 to 2050, around 5% higher than the current prices.

Figure 32: Wholesale electricity prices by region, BAU
5.6 Resource costs

Resource costs comprise the cost of inputs used to generate electricity including capital costs, fixed and variable operating costs and fuel costs.

Resource costs exhibit three trends:

- An increase in costs over the period to 2020, mainly reflective of the capital costs of additional renewable generation entering in this period. This is partly compensated for by lower fuel costs as the additional renewable generation displaces coal and gas-fired generation.

- After 2020, fuel costs dominate resource costs comprising close to 40% of total resource costs.

- After 2040, resource costs increase as new plant are needed to replace the retiring coal plant and as gas generation increases, with fuel costs from gas-fired generation being higher than for coal-fired generation.

The net present value of the resource costs for electricity generation over the 33 year period from 2017 to 2050 is estimated to be around $132 billion (at a 7% discount rate).
Figure 34: Annual resources costs, BAU

Figure 35: Present value of generation costs, BAU (2017-2050)
6. Clean Energy Target

6.1 Scenario description

Under the Clean Energy Target (CET) scenario, a new target for low emissions generation is imposed similar to the way the large-scale renewable energy target works but extended to all low emissions options with emissions intensity below 0.6 t CO$_2$-e/MWh. Unlike the large-scale renewable target, the target does not plateau but follows a trajectory to the end of the modelling period. Further unlike the large-scale renewable energy target, the target is calculated to achieve emissions reductions rather than a renewable energy target.

The required number of certificates is derived to achieve the required emissions trajectory. To achieve the emissions trajectory, the annual Clean Energy Target increases from 2,900 GWh$^{25}$ in 2020 to around 90,000 GWh in 2050. Combined with pre-existing renewable energy and projected rooftop PV this represents around 42% of total grid based generation in 2030.

The certificate price required to achieve this target increases from around $27/MWh to around $75/MWh. These prices appear to be greater than required to recover the long run marginal cost of new low emissions plant (see Section 3.3.6 and Figure 12). They are required because new plant can only earn certificates for a period of 15 years (rather than over the assumed life, which can be greater than 25 years).

![Figure 36: Clean Energy Target and certificate price, CET scenario](image)

There are no direct penalties applying to plant with emissions intensities greater than 0.6 t CO$_2$-e/MWh. There are no prohibitions to prevent high emissions plants entering the market. Existing low emissions plant have to generate above a baseline (based on historical levels) before they can earn certificates. Plant receiving certificates under the LRET scheme cannot earn certificates under the CET scheme.

Because the policy for achieving emissions reductions is now known with certainty, there is no risk premium applying to investment in new plant. Existing plant have more confidence in predicting future outcomes and can therefore better plan upgrades of existing plants. Retirement of existing plant is based on economic criteria alone.

$^{25}$ 1 MWh = 1 certificate under this scheme. Different low emissions technologies earn different portions of a certificate depending on their emissions intensity relative to the threshold rate. See Section 2.1.3.
6.2  Key findings

This scheme provides incentives for a greater level of uptake of low emissions plant. High emissions plant are displaced in the merit order either by the low emissions plant having lower dispatch costs or by using the certificate revenue to effectively act to reduce the dispatch bids below that of high emissions plant.

The results of applying these incentives through the CET are as follows:

- As with other scenarios, there is a change in the mix of generation away from coal-fired generation to largely renewable energy generation. Unlike the Business as Usual scenarios, coal-fired generation reduces slowly and there is more existing plant playing the role of meeting demand when there is limited renewable generation. There is therefore more coal-fired generation and less gas-fired generation in this scenario. Renewable generation comprises the bulk of the generation mix by 2050.

- The emissions target is met in all years. There is no significant amount of banking (additional abatement than the required annual target).

- Wholesale prices fall throughout the modelling period as the additional renewable plant have near zero dispatch costs, forcing higher cost plant to be dispatched less often. There is also a lower level of gas-fired generation in this scenario (being replaced by additional generation from existing coal-fired plant), which also puts downward pressure on wholesale prices.

- Retail prices are also lower than in the Business as Usual scenario. The decrease in the wholesale prices is partly offset by the compliance costs of purchasing certificates.

- Resource costs are higher than in the Business as Usual world as investment costs are brought forward as new low emissions plant are required earlier to meet the target and more of these plants are required.

6.3  Generation and capacity

Coal-fired generation reduces gradually over the modelling horizon from 137 TWh in 2020 to around 57 TWh in 2050. The level of coal-fired generation is generally higher than in the Business as Usual world as plant maintenance is continued and the amount of retirement of coal plant are lower.

Gas fired generation is relatively constant throughout the modelling period. In this scenario, because the operating lives of coal-fired plant are extended there is less need for new gas plant to meet demand in periods when renewable energy is not generating. This result would change if coal plants are retired earlier than suggested by the modelling.

The level of renewable generation is greater than for the Business as Usual scenario, with renewable energy generation comprising over 70% of the generation mix by 2050. Wind and solar PV generation have the largest share of renewable energy generation.

Around 12 GW (of mostly coal plant) are retired by the end of the modelling period compared with around 19 GW in the Business as Usual scenario.
Emissions mitigation policies and security of electricity supply

Figure 37: Generation mix, Clean Energy Target

Figure 38: Cumulative new capacity by technology type, Clean Energy Target
6.4 Emissions

As expected, emissions are at the emissions target set for the modelling. Each annual target is met.

The emissions intensity of the grid falls from around 0.8 t CO$_2$-e/MWh to just under 0.3 t CO$_2$-e/MWh. The reducing intensity reflects the growing proportion of renewable energy generation.

Figure 40: NEM Emissions and emissions targets, Clean Energy Target
6.5 Prices

Wholesale prices are expected to fall over the period to 2050. The fall in prices correlates with the increasing level of renewable energy generation with low dispatch costs.

Reducing prices in the middle of the day (which are lower than the time weighted prices shown in Figure 42) in this scenario limits the uptake of solar PV generation and favours generation that occurs more in the evening peak periods.

Figure 42: Wholesale electricity prices by region, Clean Energy Target
Retail prices also fall but not to the same extent as the wholesale price. This is because the compliance cost of the scheme (effectively the cost of purchasing certificates) is borne by retailers and is assumed to be passed on in retail tariffs. Whilst wholesale prices halve, the retail price only falls 10% below BAU levels.

**Figure 43 Average NEM retail prices by customer class, Clean Energy Target**

![Average NEM retail prices by customer class](image)

### 6.6 Resource costs

Resource costs are higher in this scenario than with a Business as Usual scenario. The present value of resource costs expended over the 33 years to 2050 is around $137 billion (with a 7% discount rate). This is around $4.9 billion higher than in the Business as Usual world.

The higher costs mainly come from higher capital costs due to the greater level of new renewable generation required in this scenario to meet the target. However, this is partly offset by lower fuel costs in this scenario than in other scenarios.

Capital costs make up a significant portion of total costs in this scenario (a higher portion than in any other scenario).
Figure 44: Annual resources costs, Clean Energy Target

Figure 45: Present value of generation costs, Clean Energy Target (2017-2050)
7. **Emissions Intensity Scheme**

7.1 **Scenario description**

An Emissions Intensity Scheme is designed to reward or penalise plants based on their emissions intensity relative to a sectoral baseline. The sectoral baseline is set to achieve the annual emissions targets, which in this study is the 28% target for 2030 and continuing to decline to the end of the study period. The required baseline emissions intensity to meet this target is shown in Figure 46.

Generators with emissions intensities higher than the baseline have to purchase certificates equal to their generation levels and the difference in intensity to the sectoral baseline. Generators with emissions intensities below the baseline can sell certificates equal to their generation times the difference in their emissions intensity to the baseline.

In the modelling of this scenario, the certificate price was gradually increased to achieve the required baseline emissions intensity. The certificate prices required to achieve the target are also shown in Figure 46. Certificate prices start at around $15/certificate ($15/t CO$_2$-e) and increase to just under $80/certificate ($80/t CO$_2$-e) in 2050.

Because the policy for achieving emissions reduction is now known with certainty, there is no risk premium applying to investment in new plant. Existing plant have more confidence in predicting future outcomes and can therefore better plan upgrades of existing plants. Retirement of existing plant is based on economic criteria alone.

![Figure 46: Emissions Intensity Scheme baseline and certificate price, Emissions Intensity Scheme](image)

7.2 **Key findings**

Under the Emissions Intensity Scheme, incentives are provided for a greater level of dispatch and uptake of low emissions plant. High emissions plant are penalised (having to purchase certificates) to the extent that their emissions intensity is above the baseline. Low emissions plants are provided incentives in terms of additional revenue from the sale of certificates and this reduces the net cost of new low emissions plant as well as reduces the dispatch cost of low emissions plant bidding into the market.
The results of applying these incentives through the EIS are as follows:

- There is a change in the mix of generation away from coal-fired generation to largely renewable energy generation. Coal-fired generation reduces gradually over time and there is more existing plant playing the role of meeting demand when there is limited renewable generation. There is therefore more coal-fired generation and less gas-fired generation in this scenario. Renewable generation comprises the bulk of the generation mix by 2050.

- The emissions target is met in all years. There is no significant amount of banking (additional abatement than the required annual target).

- Wholesale prices fall throughout the modelling period as the additional renewable plant have near zero dispatch costs, low emissions intensive plant can use the value of the certificates to reduce their dispatch bids and high emissions intensive plant have to purchase certificates increasing their dispatch bids.

- Retail prices are also lower than in the Business as Usual scenario due to the lower wholesale prices.

- Resource costs are higher than in the Business as Usual world as investment costs are brought forward as new low emissions plant are required earlier to meet the target and more of these plants are required. However, as existing low emissions plant are utilised more often to meet the targets there is less investment required than in the CET scenario and the EIS has the lowest resource cost difference to the BAU.

### 7.3 Generation and capacity

Projected generation is shown in Figure 47. Coal-fired generation reduces gradually over the modelling horizon from 136 TWh in 2020 to around 61 TWh in 2050. The level of coal-fired generation is generally higher than in the Business as Usual world as plant maintenance is continued and the amount of retirement of coal plant are lower. There is also less brown coal generation under the EIS than a CET, but by less than 5%.

Gas fired generation is relatively constant throughout the modelling period. In this scenario, because the operating lives of coal-fired plant are extended there is less need for new gas plant to meet demand in periods when renewable energy is not generating. This result would change if coal plants are retired earlier than suggested by the modelling. The low level of uptake of gas-fired capacity is also a function of the gas price assumed. If gas prices are lower than assumed, this would potentially lead to more uptake.

The level of renewable generation is greater than for the Business as Usual Scenario, with renewable energy generation comprising around two-thirds of the generation mix by 2050. Wind and solar PV generation have the largest share of renewable energy generation.

Around 12 GW (of mostly coal plant) are retired by the end of the modelling period compared with around 19 GW in the Business as Usual scenario.
Figure 47: Generation mix, Emissions Intensity Scheme

Figure 48: Cumulative new capacity by technology type, Emissions Intensity Scheme
7.4 Emissions

Emissions are at the emissions target set for the modelling. Each annual target is met.

The emissions intensity of the grid falls from around 0.8 t CO$_2$-e/MWh to just under 0.3 t CO$_2$-e/MWh. The reducing intensity reflects the growing proportion of renewable energy generation.
Wholesale prices are expected to fall over the period to around 2040, and then rise slightly to reach current levels by the end of the modelling period. The fall in prices correlates with the increasing level of renewable energy generation with low dispatch costs. However, by the end some gas-fired plants are also being penalised (as their emissions intensities) start exceeding the emissions intensity baselines.

Retail price movements reflect changes to the wholesale price. The cost of the permits traded under an Emissions Intensity Scheme is not passed on to retail tariffs, but rather is traded amongst generators.
Retail prices at the end of the modelling period are projected to be around current levels. Retail prices are higher on average than for a CET scheme over the modelling period.

Figure 53: Average NEM retail prices by customer class, Emissions Intensity Scheme

![Graph of average NEM retail prices by customer class](image)

### 7.6 Resource costs

Resource costs are higher in this scenario than with a Business as Usual scenario. The present value of resource costs expended over the 33 years to 2050 is around $135 billion (with a 7% discount rate). This estimate is around $3.5 billion higher than the Business as Usual scenario.

Of all the policy scenarios, an EIS has the lowest resource cost impact.

Capital costs make up a high portion of total costs in this scenario. Fuel costs are lower than for other scenarios reflecting lower levels of gas-fired generation.
Emissions mitigation policies and security of electricity supply

Figure 54: Annual resources costs, Emissions Intensity Scheme

Figure 55: Present value of generation costs, Emissions Intensity Scheme (2017-2050)
8. Limited Lifetime

Under the Limited Lifetime scenario, coal-fired are required to retire at the end of 50 years of operating life. In this scenario, this policy is enforced as the sole emissions mitigation measure.

The requirement to retire at 50 years of operating life effectively brings forward the time the plant retire when compared to Business as Usual scenario. This brings forward investment in replacement plant, with the choice of this plant dependent on economic criteria: what is the least cost combination of new plant to replace the coal-fired plant.

There is no additional measure to meet the emissions target. The requirement for closure is seen to provide the certainty to plant owners to invest in efficient and profitable refurbishment up to the time of the retirement. Because the Limited Lifetime is seen as the policy of choice for emissions mitigation, the uncertainty over future policy no longer exists and risk premium attached to policy uncertainty is removed.

8.1 Key findings

Under the requirement for limited lifetime for coal units, there is a change in the generation mix over time, and this change impacts on emissions outcomes and price trends.

The key findings for this scenario are:

- The proportion of coal generation falls over time in line with retirements due to the Limited Lifetime policy. In particular there is a large drop in the proportion of coal-fired generation from around 2030, when the large portion of the coal fleet built in the 1980s reaches their limited lifetime.

- The retired coal plants are not replaced by new coal plant even though the risk premium associated with policy uncertainty no longer applies. Rather the retired coal plants are replaced by a mixture of gas-fired generation and renewable energy generation. The modelling finds this mix to be of lower costs than a mix with new coal plant acting in base load mode.

- Emissions under this scenario fall but do not reach the 28% target reduction by 2030. However, with the large amount of retirement of the coal fleet beyond 2030, emissions fall below the modelled target for the period to 2050.

- As in the Business as Usual scenario, wholesale prices rise over the longer term to be between $85/MWh to $90/MWh. The rise in price reflects higher proportion of time that gas-fired generation sets the price. Retail prices also increase in line with the increase in the wholesale price.

- Resource costs are higher than in the Business as Usual scenario mainly due to the bringing forward of investment in new plant to replace the retired coal plant.

8.2 Generation and capacity

The generation mix is projected to change under this scenario (see Figure 56). The level of coal-fired generation falls over time, with the falls highly correlated to the closure of coal plant. Unlike in the Business as Usual scenario, there is no gradual decline in coal generation in between retirements of plant as there is no deterioration in plant performance as in the Business as Usual scenario.
Emissions mitigation policies and security of electricity supply

Figure 56: Generation mix, Limited Lifetime

Figure 57: Cumulative new capacity by technology type, Limited Lifetime
The retired coal plant is replaced (at a utility scale\(^26\)) with a mixture of about one-third gas fired plant and two-thirds additional renewable energy plant (see Figure 58). This mixture is seen as lower cost than replacement with new coal plant for several reasons:

- The high uptake of roof-top PV affects the hourly pattern of demand faced by the grid, reducing the load during the middle of the day and reducing the implied load factor.

- Even though gas prices are assumed to increase, utilising new gas-fired generation is lower cost than operating new coal plant at lower load duties to supply demand at times of the day when renewable energy options are not available.

- The choice of new plant is affected by the long term outlook and with variable sources of new generation increasing over time, this reduces the need for new base load plant. For a new coal plant, this means that although they may experience high load duty in the early years of operating, their level of operation could diminish over time making it harder to recover their relatively higher capital costs.

These results are driven by the relatively high capital costs of new coal versus the capital costs of new gas plant and new renewable energy plant, requiring a high level of duty and/or higher prices when operating to recover them over time.

Operating new gas plant is still seen as lower cost than a combination of new renewable energy combined with energy storage. The amount of storage capacity required to meet load in periods when variable forms of renewable energy are not operating is large and at this scale it is more economic under the assumptions used in this study to install new gas plant.

\(^26\) This does not include new roof-top PV capacity, which grows at the same rate in this scenario as in the BAU scenario. Retail prices and wholesale price movements, two of the main drivers of rooftop PV uptake, are roughly similar across the Limited Lifetime and Business as Usual scenarios.
8.3 Emissions

Emissions are projected to fall under the Limited Lifetime scenario. However, the closure of coal plants that have reached their Limited Lifetime in the period to 2030 is insufficient for the 28% target reduction in emissions to be met by 2030. Emissions are around 8 Mt CO$_2$-e per annum higher in 2030 than the target for that year.

However, emissions fall off sharply from 2032 and are projected to be below the modelled target from then until the end of the modelling period.

The emissions intensity of generation falls to around 0.25 t CO$_2$-e/MWh by 2050 reflecting the outcome that over half of generation comes from renewable energy sources by 2050.

Figure 59: Emissions and emissions targets in the NEM, Limited Lifetime

Figure 60: Emissions intensity of generation in the NEM, Limited Lifetime
8.4 Prices

Wholesale prices under this scenario initially rise to reflect the closure of Hazelwood power station. Entry of new renewable energy generation to meet the large-scale renewable target pushes prices down to the period to 2020. Prices then begin to rise as other coal plants are retired and as gas prices continue to rise. Prices plateau at around the range of $85/MWh to $90/MWh.

Wholesale prices from 2020 are slightly lower than in the BAU scenario due to the improved availability of the operating coal plant and the higher proportion of renewable energy generation in this scenario.

Retail prices follow the trend in wholesale prices. After initially falling, price return to current levels by 2030. Retail prices to residential customers average 31 c/kWh over the period from 2020 to 2050, or around 4% higher than current prices.

Figure 61: Wholesale electricity prices by region, Limited Lifetime

Figure 62: Average NEM retail prices by customer class, Limited Lifetime
8.5 Resource costs

Resource costs range from $8 billion per annum to $14 billion per annum. Capital costs are roughly similar to the Business as Usual scenario except that the capital cost is incurred earlier (by at least a decade).

Fuel costs comprise over half of the annual resource costs, reflecting the increasing portion of gas-fired generation combined with the assumed increasing gas price.

Over the 33 year period to 2050, the present value of resource costs are $13 billion (7% discount rate) higher than in the Business as Usual Scenario.

Figure 63: Annual resources costs, Limited Lifetime

Figure 64: Present value of generation costs, Limited Lifetime (2017-2050)
9. Limited Lifetime with Clean Energy Target

9.1 Scenario description

In the Clean Energy Target scenario there was no limit imposed on the life of the generating plant. In the scenario, there is a Limited Lifetime on plant operating in conjunction with a Clean Energy Target. The target is set to achieve the emissions target taking into account the contribution of that limiting life of plant will have on reducing emissions.

As a result, the Clean Energy Target is set at a lower level rising to around 57 TWh (compared with near 90 TWh when there is no limit on plant lifespan). Because limiting the life of generating plant ends up reducing emissions to below the target after 2030, there is no need for a certificate scheme beyond 2032 and certificate prices reduce to zero. Certificate prices before 2030 reflect the support needed to new plants entering the market at that time, which have a limited time period (to 2032) to recover investment costs.

Figure 65: Clean Energy Target and certificate price, Limited Lifetime with Clean Energy Target

9.2 Key findings

Limiting the life of generating plant results in a different change in the generation mix compared to a Clean Energy Target alone. As a result market impacts differ:

- Compared to the Clean Energy Target alone, there is more rapid and larger reduction in coal-fired generation. This is largely replaced by gas-fired generation, which is required to meet demand when renewable generation is not available. Renewable generation is also at a lower level, although still contributing around half of the generation mix by 2050.

- Because there is a higher level of gas-fired generation and certificate prices fall to zero by 2032, wholesale prices are higher in this scenario than for the CET alone. Prices after 2032 track closely to but slightly lower than prices under the BAU scenario.

- Retail prices are also higher by around 9% on average over the modelling period reflecting the higher wholesale prices.
Emissions mitigation policies and security of electricity supply

- Up to 2032, the Clean Energy Target is needed to meet the emissions target. After 2032, the Limited Lifetime regulation effectively means that emissions reductions go beyond the target level required and there is no need for a Clean Energy Target.

- Resource costs are higher than for the Business as Usual scenario and are at the highest level of all policy scenarios examined. The high costs reflect the high fuel costs from generating from gas-fired plant.

9.3 Generation and capacity

The generation mix is projected to change under this scenario (see Figure 66). The level of coal-fired generation falls over time, with the falls highly correlated to the closure of coal plant under the Limited Lifetime regulation. Compared to the Clean Energy Target alone scenario, there is less coal-fired generation.

The retired coal plant is replaced with a mixture of about one-third gas fired plant and two-thirds additional renewable energy plant (see Figure 67). This mixture is seen as lower cost than replacement with new coal plant for several reasons:

- The high uptake of roof-top PV affects the hourly pattern of demand faced by the grid, reducing the load during the middle of the day and reducing the implied load factor.

- Even though gas prices are assumed to increase, utilising new gas-fired generation is lower cost than operating new coal plant at lower load duties to supply demand at times of the day when renewable energy options are not available.

- The choice of new plant is affected by the long term outlook and with variable sources of new generation increasing over time. This reduces the need for new base load plant. For a new coal plant, this means that although they may experience high load duty in the early years of operating, their level of operation could diminish over time making it harder to recover their relatively higher capital costs.

- The cost of low emissions coal-fired technologies is higher than for other low emissions technologies and the support provided under the CET component is insufficient for these technologies to recover costs.

Operating new gas plant is still seen as lower cost than a combination of new renewable energy combined with energy storage. The amount of storage capacity required to meet load in periods when variable forms of renewable energy are not operating is large and at this scale it is more economic under the assumptions used in this study to install new gas plant.
Emissions mitigation policies and security of electricity supply

Figure 66: Generation mix, Limited Lifetime with Clean Energy Target

Figure 67: Cumulative new capacity by technology type, Limited Lifetime with Clean Energy Target
9.4 Emissions

Emissions are projected to fall under this scenario. However, implementation of a Clean Energy Target in the period to 2030 is required for the 28% reduction target to be met by 2030.

However, emissions fall off sharply from 2032 and are projected to be below the modelled target from then until the end of the modelling period. There is no need for a Clean Energy Target from this time onwards to meet the target.

The emissions intensity of generation falls to around 0.25 t CO₂-e/MWh by 2050 reflecting the outcome that over half of generation comes from renewable energy sources by 2050.
Prices

Wholesale prices under this scenario are relatively stable until around 2030. Entry of new renewable energy generation to meet the CET target pushes prices down. Prices then begin to rise as coal plants are retired and as gas prices continue to rise. Prices plateau at around the range of $85/MWh to $92/MWh.

Wholesale prices from 2020 to 2030 are slightly lower than in the BAU scenario due to the improved availability of the operating coal plant and the higher proportion of renewable energy generation.

Retail prices follow the trend in wholesale prices. After initially falling, price return to current levels by 2030. Residential retail prices average average around 1% lower than under the BAU scenario. For industrial customers, delivered prices average around 2% lower than under the BAU scenario.
Figure 71: Wholesale electricity prices by region, Limited Lifetime with Clean Energy Target

Figure 72: Average NEM retail prices by customer class, Limited Lifetime with Clean Energy Target
9.6 Resource costs

Resource costs are highest under this scenario, with the present value of resource costs being $146 billion with a 7% discount rate, some $13.9 billion higher than under the BAU.

The main component of the higher fuel costs, which make up a growing share of resource costs over the modelled period. Fuel costs comprise over half the annual resource cost from 2035.

Figure 73: Annual resources costs, Limited Lifetime with Clean Energy Target

![Graph showing annual resource costs from 2017 to 2050, with fuel cost, opex, retirement cost, and capex categories.]

Figure 74: Present value of generation costs, Limited Lifetime with Clean Energy Target (2017-2050)

![Bar chart comparing present value of generation costs between LLCET and BAU, with values in billions of dollars as of June 2016.]
10. **Limited Lifetime with Emissions Intensity Scheme**

10.1 **Scenario description**

Unlike the Emissions Intensity Scheme scenario, in this scenario there was limit imposed on the life of the generating plant. In the scenario where there is a Limited Lifetime on plant in conjunction with a Emissions Intensity Scheme, where the emissions intensity baseline under the EIS is set to achieve the emissions target taking into account the contribution that limiting life of plant will have on reducing emissions.

The emissions intensity baseline reduces from 0.7 t CO$_2$-e/MWh in 2020 to 0.3 t CO$_2$-e/MWh in 2050. However, the Limited Lifetime of generating plant reduces the level of coal-fired generation to such an extent that an Emissions Intensity Scheme is not needed after 2032, as the emissions intensity of generation is below the baseline required to just achieve the target.

**Figure 75:** Emissions Intensity Scheme baseline and certificate price, Limited Lifetime with Emissions Intensity Scheme

10.2 **Key findings**

Limiting the life of generating plant results in a different change in the generation mix compared to an Emissions Intensity Scheme alone. As a result market impacts differ:

- Compared to the Emissions Intensity alone, there is more rapid and larger reduction in coal-fired generation. This is largely replaced by gas-fired generation, which is required to meet demand when renewable generation is not available. Renewable generation is also at a lower level, although still contributing over half of the generation mix by 2050.

- Because there is a higher level of gas-fired generation and certificate prices fall to zero by 2032, wholesale prices are higher in this scenario than for the EIS alone. Prices after 2032 track closely to but lower than prices under the BAU scenario until 2040 after which they are almost the same as prices under the BAU.

- Retail prices are also higher by around 7% on average over the modelling period than for an EIS alone reflecting the higher wholesale prices.
Up to 2032, an EIS is needed to meet the emissions target. After 2032, the Limited Lifetime regulation effectively means that emissions reductions go beyond the target level required and the Emissions Intensity Scheme becomes redundant as the emissions intensity of generation is below the baseline emissions intensity.

Resource costs are higher than for the Business as Usual scenario and higher than for EIS alone scenario. The high costs reflect the high fuel costs from generating from gas-fired plant.

10.3 Generation and capacity

The generation mix is projected to change under this scenario. The level of coal-fired generation falls over time, with the falls highly correlated to the closure of coal plant under the Limited Lifetime regulation. Compared to the EIS alone scenario, there is less coal-fired generation particularly from 2032.

The retired coal plant is replaced with a mixture of about one-third gas fired plant and two-thirds additional renewable energy plant. This mixture is seen as lower cost than replacement with new coal plant for several reasons:

- The high uptake of roof-top PV affects the hourly pattern of demand faced by the grid, reducing the load during the middle of the day and reducing the implied load factor.

- Even though gas prices are assumed to increase, utilising new gas-fired generation is lower cost than operating new coal plant at lower load duties to supply demand at times of the day when renewable energy options are not available.

- The choice of new plant is affected by the long term outlook and with variable sources of new generation increasing over the modelling period, this reduces the need for new base load plant. For a new coal plant, this means that although they may experience high load duty in the early years of operating, their level of operation could diminish over time making it harder to recover their relatively higher capital costs.

- The cost of low emissions coal-fired technologies is higher than for other low emissions technologies and the support provided under the EIS is insufficient for these technologies to recover costs.
Figure 76: Generation mix, Limited Lifetime with Emissions Intensity Scheme

Figure 77: Cumulative new capacity by technology type, Limited Lifetime with Emissions Intensity Scheme
Emissions are projected to fall under this scenario. However, implementation of an EIS in the period to 2030 is required for the 28% reduction in emissions to be met by 2030.

However, emissions fall off sharply from 2032 and are projected to be below the modelled target from then until the end of the modelling period. Hence, there the EIS becomes redundant from this time onwards as the generation emissions intensity is below the baseline.

10.4 Emissions
10.5 Prices

Wholesale prices under this scenario are relatively stable until around 2030. Entry of new low emissions generation to meet the EIS target pushes prices down. Prices then begin to rise as coal plants are retired, as gas prices continue to rise and as the EIS is no longer required (with permit prices effectively zero and hence not put downward pressure on prices). Prices plateau at around the range of $85/MWh to $92/MWh.

Wholesale prices from 2020 to 2030 are slightly lower than in the BAU scenario due to the improved availability of the operating coal plant and the higher proportion of low emissions generation with effectively reduced dispatch bids.

Retail prices follow the trend in wholesale prices. After initially falling, price return to current levels by 2030. Retail prices for residential customers average around 1% lower than under the BAU scenario. Delivered prices to industrial customers average around 1% lower than for the BAU scenario.
Emissions mitigation policies and security of electricity supply

Figure 81: Wholesale electricity prices by region, Limited Lifetime with Emissions Intensity Scheme

Figure 82: Average NEM retail prices by customer class, Limited Lifetime with Emissions Intensity Scheme
10.6 Resource costs

Resource costs are highest under this scenario, with the present value of resource costs over 33 years being $145 billion with a 7% discount rate, some $13.3 billion higher than under the BAU.

The main component of the higher fuel costs, which make up a growing share of resource costs over the modelled period. Fuel costs from gas-fired generation comprise over half the annual resource cost from 2035.

Figure 83: Annual resources costs, Limited Lifetime with Emissions Intensity Scheme

Figure 84: Present value of generation costs, Limited Lifetime with Emissions Intensity Scheme (2017-2050)
11. Minimum synchronous generation constraint

11.1 Sensitivity description

For this sensitivity, the Melbourne Energy Institute (MEI) was tasked to determine the level of minimum synchronous generation inertia requirements to ensure a secure energy system at all times in Limited Life with Clean Energy Target policy since in that case there is a rapid uptake of renewable generation combined with a significant retirement of synchronous coal-fired generation. The outcome of this MEI study provided Jacobs with yearly data for minimum synchronous generation in the form of two different values:

1. The minimum yearly online synchronous output, that represents the actual generation output from synchronous generators that must be dispatching at all times in the NEM
2. The minimum yearly online synchronous capacity, that represents the annual spinning reserve requirements that must be available at all times in the NEM

The minimum synchronous capacity/output values were calculated under the assumption of one single MW figure for the minimum synchronous generation to be always online in the system. This leads to a worst-case condition, yielding a certain MW level that generally corresponds to a low demand and high renewable output case. This is also a generally conservative number and only a proxy of the actual requirements that change with the system condition.

These two different set of annual values are shown in Figure 85. The minimum synchronous generation capacity decreases to 2035 and then tends to saturate in future years. In fact, in 2017 to 2030 the wind penetration is not yet substantial, and the synchronous capacity is needed for adequacy purposes too to cover the minimum demand. However, no matter how much wind there is in the system, from 2035 the minimum synchronous generation level constraint becomes active in the system, and thus it does not change significantly with time (minimum demand level is about constant throughout those years).

Figure 85: Minimum online synchronous capacity and online synchronous output, minimum synchronous generation

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27 More details are given in the MEI report.
The minimum amount of online synchronous output is provided by MEI for the NEM as a whole. Jacobs determined the amount of synchronous output required in each region and the model then selected the most cost-effective generators to provide that minimum amount of synchronous output in each region every year.

The minimum amount of synchronous capacity is also provided by MEI for the NEM as a whole and Jacob’s model determined the generators to meet this requirement on a least cost basis.

These values are implemented as additional constraints into the model while all other assumptions remain the same as in the Limited Lifetime with Clean Energy Target policy.

In the model the only generators capable of providing the minimum synchronous generation are thermal generators. Jacobs understands that new technology developments (i.e. synchronous condensers, synthetic inertia batteries with power conversion electronics etc.) will potentially allow renewable technologies to provide these ancillary services (or at least a portion of these services) but a more conservative approach was chosen for that sensitivity in order to examine the full impact of the constraint.

11.2 Key findings

The minimum synchronous generation constraint case when compared to the Limited Lifetime with Clean Energy Target policy results in:

- The same investment in thermal capacity throughout the modelled horizon and only a slight change to the renewable capacity.
- A minor change to the generation dispatch in order to meet the synchronous generation requirement.
- The 28% emissions reduction on 2005 levels by 2030 is still met.
- A neutral impact to the retail prices.
- Slightly higher resource costs due to higher fuel costs.

Overall, the impact of the minimum synchronous generation constraint did not have a significant effect on the modelled results.

11.3 Generation and capacity

The implementation of the minimum synchronous generation constraint into the model had no impact to the new thermal capacity installed and retired over the modelled horizon, while the investment in new renewable energy is different as shown in Figure 85 due to the different generation dispatch in each region.
The difference between the generation mix in the Limited Lifetime with Clean Energy Target policy and the minimum synchronous generation case, are illustrated in Figure 87. The constraint works in the model in two different ways:

- the minimum online synchronous output forces the model to dispatch a minimum amount of synchronous generation every single hour within the modelling horizon and therefore increases the amount of thermal generation dispatch, while

- the online synchronous capacity (similar to spinning reserve) forces the model to select some synchronous generators to withhold a portion of their capacity in order to provide that ancillary service and therefore reduces the amount of thermal generation dispatch.

The combination of these two constraints results in a new generation dispatch. Throughout the 33 year modelling horizon the change to generation dispatch between the Limited Lifetime with Clean Energy Target policy and the minimum synchronous generation sensitivity is not significant, reflecting the robustness of the modelling results.
11.4 Emissions

As shown in Figure 88, the resulting NEM emissions in the minimum synchronous generation case are similar to those in the Limited Lifetime with Clean Energy Target case and they continue to be below the 28% emissions target.

Figure 88: NEM Emissions and emissions targets, minimum synchronous generation
11.5 Prices

The wholesale prices throughout the modelled horizon in the minimum synchronous generation sensitivity are on average $2/MWh lower when compared to the Limited Lifetime with Clean Energy Target policy (Figure 89), since some additional thermal synchronous generation is dispatched ahead of other plant in the merit order as a result of the ancillary service it provides.

But when the cost of providing the minimum generation ancillary services is added to the retail price, the resulting retail cost is higher than before as shown in Figure 90 (around 0.1 c/kwh on average).

Figure 89: Impact to wholesale electricity prices by region, minimum synchronous generation
11.6 Resource costs

Figure 91 shows the difference in resources costs between the Limited Lifetime with Clean Energy Target policy and the minimum synchronous case. The main changes illustrated are some capital investment in renewable capacity deferred for some years (since additional synchronous generation is dispatched instead) and small increase in fuel costs due to the additional gas and coal generation required to meet the minimum synchronous constraint. Overall, as shown in Figure 92 the present value of the resource costs over the 33 year interval range from $2 billion higher at a 7% discount rate.
Emissions mitigation policies and security of electricity supply

Figure 91: Impact to annual resources costs, minimum synchronous generation

Figure 92: Impact to present value of generation costs, minimum synchronous generation (2017-2050)
12. 10% probability of exceedance sensitivity

12.1 Scenario description

Probability of exceedance (POE) demand is a generalised approach to defining the probability of exceedance of electricity peak demand forecasts. The peak demand is expressed as the probability the forecast would be met or exceeded, e.g. a 50% POE demand implies there is a 50% probability (or 5 years in 10) of the forecast being met or exceeded. The maximum demand in any year is affected by weather conditions, temperature and humidity conditions.

All the scenarios modelled are using a 50% probability of exceedance median peak demand. The use of the 50% POE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels, generation dispatch and generation investment.

In order to assess the robustness and reliability of the modelled investment outcome of the different scenarios, a 10% probability of exceedance median peak demand is used (that is, the likelihood to exceed the peak demand forecast is only 1 year out of 10) to all the previous modelling runs. By using this conservative approach we can then determine the impact of a potential higher than average peak demand to the energy system and calculate the extra investment in capacity that is needed to meet this higher peak demand.

The modelling for this sensitivity is done based on the following methodology:

- For each modelled scenario, the investment plan and capacity mix resulting from the 50% POE peak demand is kept unchanged.
- Using this capacity mix, the 10% POE median peak demand trace is used to run the model instead of the 50% POE.
- The resulting unserved energy (USE) under the 10% POE median peak demand is reported.
- The model adds the necessary generation capacity to meet the NEM's reliability standard of 0.002 per cent unserved energy per region per financial year, which means that out of 100,000 MWh of demand, no more than 2 MWh of outage would be allowed.

**Peak demand**

The 10% POE median peak demand used in this sensitivity is taken from AEMO’s 2016 NEFR. The historical and projected non-coincidence 10% POE peak demand is shown in Figure 93, while Figure 94 illustrates the difference between the 50% POE and the 10% POE by state.

The most noticeable differences are found in New South Wales and Victoria, something that reflects a greater unpredictability of future weather conditions in those states. Overall in the NEM, the 10% POE results to around 3,500 MW per year higher non-coincidence peak demand than the 50% POE.
Figure 93: Non coincidence historical peak demand and forecast 10% POE peak demand

Figure 94: Difference between 50% POE and 10% POE peak demand by state
12.2 Impact on unserved energy

The projected investment plan resulting from the 50% POE median peak demand for each scenario has been kept unchanged. When the higher 10% POE peak demand is used with the existing investment plan it results to a higher annual unserved energy as shown in Figure 95.

Figure 95: Percentage of unserved energy per state under the 50% POE and the 10% POE prior to any additional investment
Under the 10% POE median peak demand all the modelled scenarios result to unserved energy over and above the reliability standard of 0.002% in most states. This outcome showcases the “tightness” of the energy system resulting either from the retirement of coal generators in the policy scenarios or the deterioration of coal generators’ availabilities in the BAU case.
### 12.3 New required investment

In order to address the higher unserved energy and ensure that the reliability constraint of 0.002% is not exceeded the model adds additional generation capacity on a least cost basis. The aggregated generation capacity added in each scenario throughout the modelled horizon from 2017 to 2050 is shown in Figure 96. The resulting additional capacity required is around 2-3% of the total amount of capacity in the NEM and is relatively similar to all scenarios, with only the BAU case requiring slightly higher investment.

**Figure 96: New capacity investment (OCGTs and batteries) required for 10% POE, all scenarios**

![Bar chart showing new capacity investment](Image)

*Note: The solid fill represents the OCGT capacity and the shaded fill represents the battery capacity.*

Figure 97 illustrates the net present value of the additional capital costs for the required capacity investment. It ranges from $0.88 to $1.13 billion over the modelled horizon, which is less than 1% of the total net present value of the resource costs in all scenarios. Therefore, it is concluded that even though the 10% POE median peak demand exceeds the limit of unserved energy allowed in the NEM, the capital investment to address that issue is not significant.
Figure 97: Capital costs of additional investment for 10% POE, all scenarios (2017-2050)
Appendix A. Modelling techniques

A.1 Strategist

Jacobs uses its market simulation model of the NEM to estimate the impacts on the electricity market. Electricity market modelling was conducted using Jacobs energy market database and modelling tools in conjunction with use of probabilistic market modelling software called Strategist. Strategist represents the major thermal, renewable, hydro and pumped storage resources as well as the interconnections between different regions. Average hourly pool prices are determined within Strategist based on plant bids derived from marginal costs or entered directly.

Market impacts are essentially driven by the behavioural responses of the generators to the incentives and/or regulatory requirements of the policy options being examined and the change in the mix of investment due to the incentives provided by the policy options. Wholesale prices are affected by the supply and demand balance and long-term prices being effectively capped near the long run marginal cost of new entry on the premise that prices above this level provide economic signals for new generation to enter the market. Generation mix and other impacts are also influenced by the incentives or regulations provided by the policy option being examined. Other factors affecting the timing and magnitude of the impacts include projected fuel costs, unit efficiencies and capital costs of new plant.

The market impacts take into account regional and temporal demand forecasts, generating plant performance, timing of new generation including renewable projects, existing interconnection limits and potential for interconnection development.

The primary tool used for modelling the wholesale electricity market is Strategist, proprietary software licensed from Ventyx that is used extensively internationally for electricity supply planning and analysis of market dynamics. Strategist simulates the most economically efficient unit dispatch in each market while accounting for physical constraints that apply to the running of each generating unit, the interconnection system and fuel sources. Strategist incorporates chronological hourly loads (including demand side programs such as interruptible loads and energy efficiency programs) and market reflective dispatch of electricity from thermal, renewable, hydro and pumped storage resources.

The Strategist model is a multi-area probabilistic dispatch algorithm that determines dispatch of plant within each year and the optimal choice of new plant over the period to 2050. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system. The timing of new thermal generation plant and interconnection upgrades is determined by a dynamic programming algorithm that seeks to minimise total system production and new capital costs.

The model incorporates:

- Chronological hourly loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the corresponding month.
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro plant is assumed to shadow bid to maximise revenue at times of peak demand).
- A range of bidding options for thermal plant (fixed prices, shadow bidding, average price bidding).
- Chronological dispatch of demand side programs, including interruptible loads.
- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions.
- Scheduled and forced outage characteristics of thermal plant.
The model projects electricity market impacts for expected levels of generation for each generating unit in the system. The level of utilisation depends on plant availability, their cost structure relative to other plant in the system and bidding strategies of the generators. Bids are typically formulated as multiples of marginal cost and are varied above unity to represent the impact of contract positions and price support provided by dominant market participants. Contract positions are typically assumed to apply on an N-1 basis for a portfolio of base load generation. The principles used to represent price support in the market are for moderate bids (multiples of 2 or less) on the coal-fired generating units that provide the support and more aggressive multiples on peaking generating units. These bidding behaviours are benchmarked to actual market outcomes and projected forward in the short term. In the longer term, as the market returns to supply-demand balance, strategic bidding is moderated.

New plant, whether to meet load growth or to replace uneconomic plant, are chosen on a least cost basis subject to meeting two criteria:

- To ensure electricity reliability are met under most contingencies. The parameters for quality of supply are determined in the model through the loss of load, energy not served and reserve margin. We have used a maximum energy not served of 0.002% on a regional basis, which is in line with planning criteria used by system operators.
- Revenues earned by the new plant equal or exceed the long run average cost of the new generator.

Each power plant is considered separately in the model. The plants are divided into generating units, with each unit defined by minimum and maximum operating capacity, heat rates, planned and unplanned outages, fuel costs and operating and maintenance costs. Minimum operating capacities are enforced under all policy scenarios.

Strategist also accounts for inter-regional trading, scheduled and forced outage characteristics of thermal plant (using a probabilistic mechanism), and the implementation of government policies such as the Renewable Energy Target (RET) schemes.

Timing of new generation is determined by a generation expansion plan that defines the additional generation capacity that is needed to meet future load or cover plant retirements by maintaining minimum reserve and reliability standards. As such by comparing a reference case to a policy scenario, we can quantify any deferred generation benefits. The expansion plan has a sustainable wholesale market price path, applying market power where it is evident, a consistent set of renewable and thermal new entry plant and a requirement to meet reserve constraints in each region. Every expansion plan for the reference and policy scenarios in this study has been checked and reviewed to ensure that these criteria are met.

Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, Jacobs partitions Queensland into three zones to better model the impact of transmission constraints and the trends in marginal losses and generation patterns change in Queensland. These constraints and marginal losses are projected into the future based on past trends.

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 98 and the Jacobs modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in Figure 99.

The PROVIEW module of Strategist is used to develop the expansion plan with a view to minimising the total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However due to computational burden and structural limitations of the Strategist package, in one simulation it was not feasible to complete:

- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation), and
Emissions mitigation policies and security of electricity supply

- A review of the contract positions and the opportunity to exercise market power.

We therefore, conducted a number of iterations of PROVIEW to develop a workable expansion plan and then refined the expansion plan to achieve a sustainable price path applying market power where it was apparent and to obtain a consistent mix of new entry plant.

Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Interregional capacity is increased in line with capacity needed to avoid prolonged substantial price separation between interconnected regions, with price separation not being greater than typical line losses.

**Figure 98: Strategist Analysis Flowchart**

- Load shapes and peak and energy forecasts by region
- Scale typical weekly load shapes to hourly values to match the forecast
- Dispatch hydro and demand side resources into peak of local or regional aggregate load curve, run-of-river output reduces base load demand
- Calculate thermal plant marginal costs and multiply by bid factors or replace with fixed or shadow bids as specified
- Build a marginal prices versus thermal supply for each region
- Solve for average marginal prices across the regions
- Networking losses and capacity
- Net thermal load to be supplied in each region, imports and exports
- Calculate the load in each region to be supplied from thermal or traded resources
- Probabilistic thermal dispatch including fuel constraints
- OUTPUT HOURLY PRICES
- OUTPUT GENERATION AND FUEL CONSUMPTION
A.2 REMMA

The renewable energy market under any renewable energy target scheme was modelled in REMMA. REMMA is a tool that estimates a least cost renewable energy expansion plan, and solves the supply and demand for LGCs having regard to the underlying energy value of the production for each type of resource (base load, wind, solar, biomass with seasonality).

Strategist was run in conjunction with the renewable energy market model to determine the wholesale market solution that is also compatible and most efficient with regard to renewable energy markets. Additional renewable generation has the effect of reducing wholesale prices while reduced wholesale prices typically have the effect of reducing investment in renewable generation. Iteration of these models typically allows the overall solution to converge to a stable model of consistent wholesale and renewable energy markets.

The REMMA model the impact of policies affecting an expanded target or through external price incentives to be simulated. Uptake of renewable generation, both its timing and location, is affected both by mandated targets and the impacts of other policies designed to reduce emissions of greenhouse gases.

A.2.1 Model Structure

Projecting certificate prices with the REMMA model is based on the assumption that the price of the certificate will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic premise behind the method is that the certificate provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the mandatory target economic without further subsidisation. The REMMA uses a linear programming algorithm to determine least cost uptake of renewable technologies to meet the target, subject to constraints in resource
availability and regulatory limits on uptake, whilst also taking into account the penalty price for any shortfall in meeting the target. The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required over the period to 2030 when the program is scheduled to terminate. The model has an explicit variable that measures non-compliance with the target (i.e. a shortfall of renewable energy generation), which can be set to a positive value if doing so minimises the total cost of the scheme (i.e. it is cheaper to violate the target by paying the penalty price). Therefore the ability for the RET to be met economically is an output of the model.

The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects. Jacobs has a detailed database of renewable energy projects (existing, committed and proposed) that supports our modelling of the renewable uptake. The database includes estimation of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for over 900 individual projects.

The model can be readily extended to include other forms of low emissions generation. The model already includes waste coal mine gas as an option to meet a separate target.
## Appendix B. Emissions reduction policies – Design features

<table>
<thead>
<tr>
<th>Design issue</th>
<th>Assumption</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Overarching issues</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assistance to Emissions intensive, trade exposed (EITE) industries</td>
<td>• No EITE industry assistance will be considered</td>
<td>• Has no impact on cost of policies, just distribution of costs</td>
</tr>
<tr>
<td>Existing Renewable Energy Target (RET)</td>
<td>• The LRET will stay as it is for all scenarios.</td>
<td>• LRET is built in to the BAU</td>
</tr>
<tr>
<td></td>
<td>• Under CET scenarios, the large-scale renewable energy target remains as it is, and the CET will operate separately.</td>
<td>• In the policy scenarios, investment to meet the LRET remains unchanged from the reference case. That is, we assume investors will invest based on existing economics and will not delay their investment to take advantage of a new scheme.</td>
</tr>
<tr>
<td><strong>Clean Energy Target (CET)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eligibility of generators</td>
<td>• All new (from 2020) large-scale renewable generators, including commercial scale PV (systems larger than 10 kW)</td>
<td>• To ensure technology neutrality, the scheme should be open to all new generators and existing generators below the emissions intensity threshold.</td>
</tr>
<tr>
<td></td>
<td>• All new fossil fuel generators with an emissions intensity below the threshold</td>
<td>• However, to avoid providing a windfall gain to existing fossil fuel and renewable generators, they are only eligible for generation in excess of their historical baselines.</td>
</tr>
<tr>
<td></td>
<td>• Existing low emissions fossil fuel generators and renewable generators are eligible for generation that exceeds historic baseline levels (see below).</td>
<td></td>
</tr>
<tr>
<td>Design issue</td>
<td>Assumption</td>
<td>Rationale</td>
</tr>
<tr>
<td>-----------------------------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Emissions intensity threshold for eligibility to earn certificates</td>
<td>• An emissions intensity threshold be set at 0.6 ( t \text{CO}_2\text{-e}/\text{MWh} ).</td>
<td>• An emissions intensity threshold of 0.6 ( t \text{CO}_2\text{-e}/\text{MWh} ) would enable participation by low emissions fossil fuel plant.</td>
</tr>
<tr>
<td>How many certificates?</td>
<td>• Certificates will be earned in proportion to the difference between the generator’s emissions intensity and the emissions intensity threshold.</td>
<td>• The aim of the policy is to reduce emissions. Therefore, it is reasonable to reward generators that have the lowest emissions intensities. For example generator A has an emissions intensity of 0.3 ( t \text{CO}_2\text{-e}/\text{MWh} ). Since the emissions intensity threshold is 0.6 ( t \text{CO}_2\text{-e}/\text{MWh} ), Generator A will earn 0.5 certificates for each MWh generated since ( (0.6 - 0.3)/0.6 = 0.5 ).</td>
</tr>
<tr>
<td>Historical baseline for existing generation</td>
<td>• Create a baseline for existing gas and renewable generators. This baseline will be based on the average amount of electricity each generator produces from 2018 to 2020 (or whichever years the generator operates in that period).</td>
<td>• Creating a baseline for gas and renewable generation aims to encourage ramp up for existing generation while avoiding providing certificates for electricity that would have been produced anyway.</td>
</tr>
<tr>
<td>Parameters to meet emissions constraints</td>
<td>• Since the CET will operate separately from the existing RET, the CET trajectory would grow from zero in 2020 and will continue rising to 2050. That is, it will not flatten out.</td>
<td>• The scenario being modelled represents a world where the CET provides a long term signal for new investment in low emissions technologies. As such, the target continues to grow throughout the projection period.</td>
</tr>
<tr>
<td>Banking and borrowing</td>
<td>• Unlimited banking&lt;br&gt;• Borrowing limited to 10 per cent of the following year’s certificates</td>
<td>• Unlimited banking is allowed under the current RET, so this approach would be extended to the new CET.&lt;br&gt;• Banking reduces price volatility. Without banking, the price of certificates would drop to zero once demand for the year is met.&lt;br&gt;• To mitigate against the risk of a shortage in available certificates, a limited amount of borrowing is permitted.</td>
</tr>
</tbody>
</table>

Emissions Intensity Scheme
## Emissions mitigation policies and security of electricity supply

<table>
<thead>
<tr>
<th>Design issue</th>
<th>Assumption</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coverage/liability</td>
<td>All generators on the NEM, would be liable (if above the emissions intensity baseline) or eligible to create permits (if they are below the baseline).</td>
<td>The wider the scope of coverage, the more opportunities to access lower cost abatement.</td>
</tr>
<tr>
<td>Availability of international offsets</td>
<td>No domestic or international offsets will be allowed</td>
<td>Low cost offsets risks no action being taken to lower emissions in Australia’s electricity sector. If sector relies on offsets, it may be more difficult to meet future targets.</td>
</tr>
<tr>
<td>Emissions intensity baseline for the sector</td>
<td>Baseline will be set consistent with the target being modelled. The baseline will start at grid average emissions intensity in 2020, declining linearly to the level in 2050 necessary to meet the target</td>
<td>Helps ensure scheme delivers required emissions reductions.</td>
</tr>
<tr>
<td>Banking and borrowing</td>
<td>Unlimited banking Borrowing limited to 10 per cent of the following year’s obligation</td>
<td>Banking makes prices far less volatile. Without banking, certificates would be worthless as soon as there are sufficient credits available to meet demand for the year. To mitigate against the risk of a shortage in available certificates, a limited amount of borrowing is permitted.</td>
</tr>
</tbody>
</table>

### Limited Lifetime

<table>
<thead>
<tr>
<th>Requirement to close ‘by’ a certain date or ‘at’ a certain date</th>
<th>Basis for determining closure date</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal-fired generators</td>
<td>Close ‘by’ a certain date</td>
<td>The Limited Lifetime will apply to coal-fired generators, since coal is the most emissions-intensive fuel source. Closing ‘by’ a date provides certainty to the market operator and new investors, supporting security and reliability.</td>
</tr>
<tr>
<td>50 year economic life Generators withdraw on a unit by unit basis</td>
<td></td>
<td>The advantage of using economic life is that it spreads the closure of generators geographically. Closing on an emissions intensity basis would first require</td>
</tr>
</tbody>
</table>
### Emissions mitigation policies and security of electricity supply

<table>
<thead>
<tr>
<th>Design issue</th>
<th>Assumption</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>shutting down brown coal plants. These are all located in Victoria and could exacerbate security and reliability issues.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Closing plants once they reach 50 years also ensures that plants can operate sufficiently long to generate their planned return on investment. Therefore, there is less need for the Government to compensate plants.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Limited Lifetime with Clean Energy Target</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Requirement to close ‘by’ a certain date or ‘at’ a certain date</td>
<td>Close ‘by’ a certain date</td>
<td>As above</td>
</tr>
<tr>
<td>Basis for determining closure date</td>
<td>50 year economic life</td>
<td>As above</td>
</tr>
<tr>
<td>New entrant standard</td>
<td>There are no new entrant standards</td>
<td></td>
</tr>
<tr>
<td>Parameters to meet emissions constraints</td>
<td>The CET trajectory would grow from zero in 2020 and will continue rising to 2050. That is, it will not flatten out.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>The level of the CET should be designed to achieve the extra emissions reduction (ie. not delivered by Limited Lifetime) required to meet the target.</td>
<td>The scenario being modelled represents a world where the CET provides a long term signal for new investment in low emissions technologies. As such, the target continues to grow throughout the projection period.</td>
</tr>
<tr>
<td>Other CET parameters</td>
<td>As above</td>
<td>As above</td>
</tr>
</tbody>
</table>
### Design issue

<table>
<thead>
<tr>
<th><strong>Assumption</strong></th>
<th><strong>Rationale</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Limited Lifetime with Emissions Intensity Scheme</strong></td>
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<td>Requirement to close ‘by’ a certain date or ‘at’ a certain date</td>
<td>Close ‘by’ a certain date</td>
</tr>
<tr>
<td>Basis for determining closure date</td>
<td>50 year economic life</td>
</tr>
<tr>
<td>New entrant standard</td>
<td>There are no new entrant standards</td>
</tr>
<tr>
<td>Parameters to meet emissions constraints</td>
<td>Baseline will be set consistent with the target being modelled.</td>
</tr>
<tr>
<td></td>
<td>The baseline will start at grid average emissions intensity in 2020, declining linearly to the level in 2050 necessary to meet the target</td>
</tr>
<tr>
<td>Other EIS parameters</td>
<td>As above</td>
</tr>
</tbody>
</table>

Note: With the exception of the Business as Usual scenario (BAU), in all other cases coal-fired plants undergo all the required major refurbishments, as there is greater policy certainty. Since these major refurbishments are performed, there is no explicit closure rule (such as the 60 year closure rule in the BAU). Instead, units will only close when it is in their economic interests.
Appendix C. Costs and performance of thermal plants

The following table shows the parameters for power plants used in the Strategist model. Costs are reported in June 2016 dollars for FY2016. The impact of carbon price on variable costs is not included in the table. The source for this information is Jacobs’ database of generation costs, which in turn is based on market data published by AEMO, annual reports of generators and fuel suppliers, ASX announcements and other media releases.

<table>
<thead>
<tr>
<th>Plant</th>
<th>No Units</th>
<th>Fuel Type</th>
<th>Total Sent Out Capacity (MW)</th>
<th>Scheduled Maintenance (Weeks pa)</th>
<th>Effective Forced Outage Rate</th>
<th>Available Capacity factor</th>
<th>Full Load Heat Rate (GJ/MWh)</th>
<th>Fixed O&amp;M $/kW/year</th>
<th>Variable O&amp;M ($/MWh)</th>
<th>Variable Fuel Cost $/GJ</th>
<th>Total Variable Cost $/MWh</th>
<th>Emissions Intensity kg CO₂-e/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tasmania</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tamar Valley CCGT</td>
<td>1</td>
<td>Gas</td>
<td>202</td>
<td>1.9</td>
<td>3%</td>
<td>93.60%</td>
<td>7.9</td>
<td>38</td>
<td>2.91</td>
<td>5.30</td>
<td>42.65</td>
<td>473</td>
</tr>
<tr>
<td>Bell Bay GT</td>
<td>3</td>
<td>Gas</td>
<td>119</td>
<td>3.0</td>
<td>1%</td>
<td>93.30%</td>
<td>12.9</td>
<td>14</td>
<td>4.36</td>
<td>11.13</td>
<td>140.15</td>
<td>720</td>
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<tr>
<td>Tamar Valley OCGT</td>
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<td>Gas</td>
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<td>1%</td>
<td>93.30%</td>
<td>12.1</td>
<td>14</td>
<td>4.36</td>
<td>11.13</td>
<td>132.36</td>
<td>677</td>
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<td>Victoria</td>
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<td></td>
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<tr>
<td>AGL Somerton</td>
<td>4</td>
<td>Gas</td>
<td>162</td>
<td>4.0</td>
<td>9%</td>
<td>83.90%</td>
<td>14.2</td>
<td>14</td>
<td>2.91</td>
<td>10.38</td>
<td>143.10</td>
<td>829</td>
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<tr>
<td>Bairnsdale</td>
<td>2</td>
<td>Gas</td>
<td>84</td>
<td>3.0</td>
<td>1%</td>
<td>93.30%</td>
<td>11.2</td>
<td>14</td>
<td>4.36</td>
<td>10.28</td>
<td>113.38</td>
<td>541</td>
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<td>Jeeralang A</td>
<td>4</td>
<td>Gas</td>
<td>231</td>
<td>2.1</td>
<td>1%</td>
<td>95.00%</td>
<td>14.6</td>
<td>14</td>
<td>8.74</td>
<td>10.28</td>
<td>150.67</td>
<td>845</td>
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<tr>
<td>Jeeralang B</td>
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<td>Gas</td>
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<td>2.1</td>
<td>1%</td>
<td>95.00%</td>
<td>13.6</td>
<td>14</td>
<td>8.74</td>
<td>10.28</td>
<td>141.41</td>
<td>790</td>
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<tr>
<td>Laverton North</td>
<td>2</td>
<td>Gas</td>
<td>338</td>
<td>2.0</td>
<td>2%</td>
<td>93.90%</td>
<td>12.2</td>
<td>14</td>
<td>4.36</td>
<td>10.38</td>
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<td>Brown Coal</td>
<td>2043</td>
<td>2.5</td>
<td>4%</td>
<td>91.90%</td>
<td>12.2</td>
<td>89</td>
<td>1.17</td>
<td>0.52</td>
<td>7.20</td>
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<tr>
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<td>966</td>
<td>2.5</td>
<td>3%</td>
<td>92.30%</td>
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<td>89</td>
<td>1.17</td>
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<td>6</td>
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<td>1%</td>
<td>95.00%</td>
<td>14.6</td>
<td>14</td>
<td>8.74</td>
<td>10.28</td>
<td>150.67</td>
<td>845</td>
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<tr>
<td>Yallourn W</td>
<td>4</td>
<td>Brown Coal</td>
<td>1362</td>
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<td>6%</td>
<td>88.60%</td>
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<td>90</td>
<td>3.48</td>
<td>0.53</td>
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<tr>
<td>Newport</td>
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<td>Gas</td>
<td>485</td>
<td>2.2</td>
<td>3%</td>
<td>93.00%</td>
<td>10.9</td>
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<td>2.91</td>
<td>4.95</td>
<td>53.90</td>
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<td>Mortlake OCGT</td>
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<td>Gas</td>
<td>550</td>
<td>2.5</td>
<td>2%</td>
<td>93.00%</td>
<td>11.0</td>
<td>14</td>
<td>3.70</td>
<td>10.38</td>
<td>111.70</td>
<td>530</td>
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<tr>
<td>Plant</td>
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<td>Fuel Type</td>
<td>Total Sent Out Capacity (MW)</td>
<td>Scheduled Maintenance (Weeks pa)</td>
<td>Effective Forced Outage Rate</td>
<td>Available Capacity factor</td>
<td>Full Load Heat Rate (GJ/MWh)</td>
<td>Fixed O&amp;M $/kW/year</td>
<td>Variable O&amp;M ($/MWh)</td>
<td>Variable Fuel Cost $/GJ</td>
<td>Total Variable Cost $/MWh</td>
<td>Emissions Intensity kg CO$_2$-e/MWh</td>
</tr>
<tr>
<td>--------------</td>
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<td>------------------------------</td>
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<td>-------------------</td>
<td>----------------------</td>
<td>--------------------------</td>
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</tr>
<tr>
<td>Qenos Cogen</td>
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<td>Gas</td>
<td>21</td>
<td>2.0</td>
<td>3%</td>
<td>93.30%</td>
<td>11.6</td>
<td>28</td>
<td>2.10</td>
<td>10.38</td>
<td>116.33</td>
<td>676</td>
</tr>
<tr>
<td><strong>South Australia</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Angaston</td>
<td>1</td>
<td>Diesel</td>
<td>50</td>
<td>0.0</td>
<td>1%</td>
<td>99.40%</td>
<td>9.5</td>
<td>14</td>
<td>12.49</td>
<td>20.72</td>
<td>198.97</td>
<td>663</td>
</tr>
<tr>
<td>Dry Creek</td>
<td>3</td>
<td>Gas</td>
<td>147</td>
<td>5.6</td>
<td>3%</td>
<td>86.10%</td>
<td>17.9</td>
<td>14</td>
<td>8.74</td>
<td>10.91</td>
<td>194.13</td>
<td>863</td>
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<td>Hallett</td>
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<td>4.0</td>
<td>4%</td>
<td>88.30%</td>
<td>10.1</td>
<td>14</td>
<td>9.98</td>
<td>10.91</td>
<td>114.67</td>
<td>1200</td>
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<td>Ladbroke Grove</td>
<td>2</td>
<td>Gas</td>
<td>84</td>
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### Emissions mitigation policies and security of electricity supply

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## Appendix D. Technology cost assumptions

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<th>Capital cost de-escalator % pa</th>
<th>Heat rate at maximum capacity GJ/MWh</th>
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### Emissions mitigation policies and security of electricity supply

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<td>0.2</td>
<td>10</td>
<td>10.3</td>
<td>27</td>
</tr>
<tr>
<td>Open Cycle Gas Turbine (Brown Field)</td>
<td>30</td>
<td>196</td>
<td>1.40%</td>
<td>1597</td>
<td>0.7</td>
<td>9.52</td>
<td>10.3</td>
<td>28</td>
</tr>
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<td>Open Cycle Gas Turbine (Green Field)</td>
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<td>1597</td>
<td>0.7</td>
<td>9.52</td>
<td>10.3</td>
<td>28</td>
</tr>
<tr>
<td>Hydro</td>
<td>35</td>
<td>30</td>
<td>2.00%</td>
<td>3589</td>
<td>0.5</td>
<td>n/a</td>
<td>5</td>
<td>35</td>
</tr>
<tr>
<td>Pumped Hydro</td>
<td>35</td>
<td>up to 300</td>
<td>2.00%</td>
<td>700-1700[3]</td>
<td>0.5</td>
<td>n/a</td>
<td>6</td>
<td>25</td>
</tr>
<tr>
<td>Wind</td>
<td>25</td>
<td>100</td>
<td>2.00%</td>
<td>2400</td>
<td>1.5(^{28})</td>
<td>n/a</td>
<td>5</td>
<td>40</td>
</tr>
<tr>
<td>Flat Plate PV (fixed)</td>
<td>20</td>
<td>50</td>
<td>2.00%</td>
<td>2190</td>
<td>4.5 / 3.5(^{29})</td>
<td>n/a</td>
<td>2</td>
<td>25</td>
</tr>
<tr>
<td>Flat Plate PV (single-axis )</td>
<td>20</td>
<td>50</td>
<td>2.00%</td>
<td>2300</td>
<td>4.5 / 3.5(^{29})</td>
<td>n/a</td>
<td>2</td>
<td>35</td>
</tr>
<tr>
<td>Concentrating PV</td>
<td>30</td>
<td>150</td>
<td>3.00%</td>
<td>6332</td>
<td>2.5(^{28})</td>
<td>n/a</td>
<td>5</td>
<td>45</td>
</tr>
</tbody>
</table>

\(^{28}\) After 2036 the de-escalator used for wind and all the different solar technologies drops to 0.3% since it they are considered mature technologies

\(^{29}\) Both the fixed and the single-axis flat plate PVs have two different de-escalators, a 4.5% up to 2025 and 3.5% after that and up to 2036 (while 0.3% is used after 2036)
## Emissions mitigation policies and security of electricity supply

<table>
<thead>
<tr>
<th>Technology type</th>
<th>Life</th>
<th>Nominal capacity</th>
<th>Auxiliary load</th>
<th>Capital cost, 2017</th>
<th>Capital cost de-escalator</th>
<th>Heat rate at maximum capacity</th>
<th>Variable non-fuel operating cost</th>
<th>Fixed operating cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concentrated solar thermal plant - without storage</td>
<td>35</td>
<td>150</td>
<td>5.00%</td>
<td>6265</td>
<td>2.5&lt;sup&gt;28&lt;/sup&gt;</td>
<td>n/a</td>
<td>5</td>
<td>50</td>
</tr>
<tr>
<td>Concentrated solar thermal plant - with storage</td>
<td>35</td>
<td>150</td>
<td>5.00%</td>
<td>8,500</td>
<td>2.5&lt;sup&gt;28&lt;/sup&gt;</td>
<td>n/a</td>
<td>4</td>
<td>65</td>
</tr>
<tr>
<td>Biomass – Steam</td>
<td>30</td>
<td>30</td>
<td>6.30%</td>
<td>6544</td>
<td>0.5</td>
<td>14.24</td>
<td>8</td>
<td>60</td>
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<tr>
<td>Biomass - Gasification</td>
<td>25</td>
<td>79</td>
<td>22.30%</td>
<td>9000</td>
<td>3</td>
<td>14.14</td>
<td>10</td>
<td>60</td>
</tr>
<tr>
<td>Geothermal - Hydrothermal</td>
<td>30</td>
<td>50</td>
<td>8.00%</td>
<td>6665</td>
<td>1</td>
<td>13</td>
<td>5</td>
<td>50</td>
</tr>
<tr>
<td>Geothermal - Hot Dry Rocks</td>
<td>25</td>
<td>50</td>
<td>10.00%</td>
<td>12600</td>
<td>1</td>
<td>14</td>
<td>5</td>
<td>50</td>
</tr>
</tbody>
</table>