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COAG Energy Council

Dear Ministers

I am pleased to enclose the Final Design of the National Energy Guarantee (the Guarantee) for your consideration.

The Guarantee integrates energy and emissions policy in a way that encourages new investment in both low emissions technologies and in dispatchable energy such that the electricity system achieves its share of emissions reduction targets and operates reliably. It is designed to deliver long-term policy confidence and stability to reduce investment risk and bring down electricity prices.

The Guarantee has five key drivers that will work together to lower retail prices:

- policy stability unlocking new investment
- policy stability reducing the risk (and therefore the cost) of new investments
- increased contracting unlocking new investment
- increased contracting in deeper and more liquid contract markets to reduce the level and volatility of spot prices, and
- increased voluntary demand response.

The final design is the culmination of almost a year’s work and a collaborative effort by people and organisations from across the energy sector and the community. Stakeholders have been clear with the Energy Security Board (ESB) that the status quo is simply not acceptable and have demonstrated a commitment to work together to respond to the changes that are underway in the energy market.

Many stakeholders have stressed that at least some of the existing pipeline of new investment is predicated on the assumption that integrated energy and climate policy is now within reach. Any delay, or worse a failure to reach agreement, will simply prolong the current investment uncertainty and deny customers more affordable energy. The strength of the Guarantee mechanism reflects the open and constructive input we have received via written submissions, technical working groups, and public forums at each step of the process.

The ESB has designed the Guarantee mechanism to be fuel and technology neutral and provide a clear investment signal so that the cheapest, cleanest and most reliable generation (or demand response) gets built in the right place at the right time. There is no revenue collected from the Guarantee and there is no certificate trading scheme.

The design incorporates specific measures to safeguard competition, and to enhance liquidity and pricing transparency in retail and wholesale markets. Importantly, the Guarantee is a flexible mechanism that can accommodate different levels of emissions ambition over time, and work with state and territory emissions targets and renewable energy schemes to create greater confidence for the industry.
The attached final design includes extensive, updated modelling led by the ESB, in partnership with the Australian Energy Market Commission, drawing on expert advice and capability from ACIL Allen consulting. The modelling by ACIL Allen (as with the modelling previously conducted for the ESB by Frontier Economics) uses an economic model of the wholesale electricity market and prices to forecast likely changes in the generation mix under different policy settings and the consequential impact on customer bills. This is in contrast to the Australian Energy Market Operator’s Integrated System Plan modelling which is a cost-based engineering assessment focused on long-term transmission planning and investment.

The most recent Guarantee modelling by ACIL Allen validates the conclusions of the modelling previously undertaken by Frontier Economics on the Guarantee. This analysis confirms that the mechanism can deliver much needed savings for households and businesses that have been impacted by rising energy prices and can ensure the electricity sector contributes its share towards Australia’s international emissions reduction commitments, all while ensuring we have sufficient dispatchable resources for reliable power. The average household bill is expected to be $550 lower each year through the 2020s than it is now, and $150 of those savings are because of the Guarantee.

Should the Energy Council choose to proceed, the Guarantee would be implemented through existing governance arrangements for the National Electricity Market.

The Energy Security Board looks forward to discussing this with you at the next Energy Council meeting on Friday 10 August 2018.

Yours sincerely

Kerry Schott AO
Chair, Energy Security Board
1 August 2018
The National Energy Guarantee (the Guarantee) is a mechanism designed to integrate energy and emissions policy in a way that encourages new investment in both low emissions technologies and in dispatchable energy such that the electricity system operates reliably. Providing long-term policy confidence is critical to lowering investment risk in the National Electricity Market (NEM) and bringing down electricity prices.

The Guarantee requires retailers to contract with generation, storage or demand response so that:

- there are contracts in place to support a minimum amount of dispatchable energy to meet consumer and system needs (reliability requirement), and
- the average emissions level of the electricity sold to consumers meets the electricity sector’s share of Australia’s international emissions reduction commitments, as set by the Australian Government (emissions reduction requirement).

The emissions reduction and reliability requirements work together so that the market has a fair opportunity to deliver adequate reliability while lowering emissions. The Guarantee is fuel and technology neutral and provides a clear investment signal, so the cleanest, cheapest and most reliable generation (or demand response) gets built in the right place at the right time.

The Guarantee has five key drivers that will work together to lower retail prices:

- policy stability unlocking new investment
- policy stability reducing the risk (and therefore the cost) of new investments
- increased contracting unlocking new investment
- increased contracting in deeper and more liquid contract markets to reduce the level and volatility of spot prices, and
- increased voluntary demand response.

NEM average wholesale prices are, on average, expected to be over 20 per cent lower over the 2020s under the Guarantee than without it. Lower wholesale prices are expected to translate into lower bills for all consumers. The average NEM-connected household is estimated to save around $550 dollars a year (real $2018) on their retail bill over the 2020s relative to 2017-18. Of this, nearly $150 per year (real $2018) is forecast additional savings as a result of the Guarantee.

The Guarantee is specifically designed so that it does not undermine, and may indeed boost, competition through measures that enhance market liquidity and pricing transparency in retail and wholesale electricity markets. Under the emissions reduction requirement, smaller retailers are supported through the exemption of the first 50,000 MWh of load and with relatively greater flexibility to carry forward any over-achievement. Under the reliability requirement, when the reliability obligation is triggered, a Market Liquidity Obligation will require the largest participants to offer to buy and sell contracts with all participants.

It is possible that higher emissions reduction targets may be set in the future by the Australian Government. In this case, the Guarantee mechanism and framework will automatically accommodate the new targets. Further, the design of the Guarantee does not limit the ability of States and Territories to set and meet their own emissions reduction or renewable energy targets.

**Emissions reduction requirement**

The emissions reduction requirement is an annual obligation on market customers in the NEM. Market customers must ensure the average emissions intensity of their load is at or below the prescribed ‘electricity emissions intensity target’ for the compliance period.
The reliability requirement is designed to incentivise retailers and other market customers (liable entities) to support the reliability of the NEM through their contracting and investment in resources.

Compliance with the emissions reduction requirement is assessed annually by the Australian Energy Regulator (AER), based on a financial year compliance period. The first compliance year proposed is 2020-21. An emissions registry, administered by the Australian Energy Market Operator (AEMO), will be established to facilitate efficient compliance.

The registry allows market customers to be allocated a share of a generator’s output and its associated emissions, for which they have obtained the rights. The registry automatically matches emissions to each market customer based on the generation allocated against their load. Market customers that do not have generation allocated for some or all their load will be assigned the average emissions intensity of all unallocated generation in the registry, to cover their unallocated load.

The AER will compare each market customer’s average emissions intensity against the electricity emissions intensity target to assess compliance. To provide flexibility, market customers can carry forward a limited amount of over-achievement for use in the next compliance year. Similarly, limited deferral is allowed.

Some elements of the final design have been revised from the draft detailed design of 15 June 2018, based on stakeholder feedback through the consultation process. These are:

- The emissions reduction requirement has been designed as a whole-of-market mechanism, in that every megawatt-hour (MWh) of generation that occurs in a compliance year will be recorded in the registry for allocation against every MWh of market customer load in that compliance year. This includes pre-1997 renewable generation (such as Snowy Hydro and Hydro Tasmania).
- The approach to over-allocations of generation has been revised. Market customers have an incentive to reallocate generation in advance of the reporting deadline. Over-allocations will not attract a civil penalty.
- The carry forward limit has increased, to up to 10 per cent of the first year’s electricity emissions intensity target per MWh of load plus a fixed amount of 60,000 tCO₂-e.
- In the first year, market customers can defer their full compliance obligation, but any deferral must be made up in the following years.

The Energy Security Board (ESB) reconsidered the need for a requirement that generators allocate all generation and associated emissions, a requirement against unreasonably withholding allocations, and a general anti-avoidance regime. These elements are not included in the final design. The AER will actively monitor the behaviour of registry participants and, if required, the ESB will reconsider the need for a general anti-avoidance regime and/or an unreasonable withholding provision.

Reliability requirement

The reliability requirement is designed to incentivise retailers and other market customers (liable entities) to support the reliability of the NEM through their contracting and investment in resources.

AEMO will forecast annually whether the reliability standard is likely to be met [or not] in each NEM region over a 10-year period. Where a reliability gap is identified, the market will have the opportunity to invest to close that gap. However, if a material gap persists or emerges three years from the period in question, then AEMO will apply to the AER to trigger the reliability obligation.

If the reliability obligation is triggered, liable entities may be required to demonstrate future compliance by entering into sufficient qualifying contracts for dispatchable capacity (including demand response) to cover their share of a one in two-year system peak demand at the time of the gap.

One year from the forecast reliability gap, if the AER confirms a material gap in resources remains, AEMO will use its safety-net Procurement of Last Resort to close the remaining gap. At this point, liable entities must disclose their contract positions to the AER. If actual system peak demand in the compliance year exceeds that which would be expected to occur once in every two years, then the AER will assess the compliance of liable entities. Those whose required share of load is not covered by qualifying contracts for the specified period are non-compliant.

Some elements of the final design have been revised from the draft detailed design of 15 June 2018, based on stakeholder feedback through the consultation process. These are:

- Large customers will be provided the flexibility to ‘opt-in’ to manage their own reliability obligation, if they consider this is the most cost-effective and efficient approach.

1 The regions of the National Electricity Market include Queensland, New South Wales, Victoria, Tasmania and South Australia.
Executive Summary

- Retailers can adjust their contract position within the compliance year when they take on new commercial and industrial customer sites with historic peak load less than 30 MW.
- Large vertically integrated retailers will be covered by a Market Liquidity Obligation when the reliability obligation is triggered. Obligated entities will be determined based on a size threshold and required to perform a market making function for the duration of the gap period. Qualifying contracts will not be required to be recorded in a trade repository with associated trade reporting for the purposes of the Guarantee.
- Liable entities found to be non-compliant with their contracting obligations will be charged an amount that contributes to the costs of AEMO exercising its Procure of Last Resort function. This will be a proportionate cost contribution commensurate with the non-compliance, determined after the event and capped at $100 million.

Governance

The Guarantee is to be implemented through two legislative routes. The first route is through the existing governance arrangements for the NEM, agreed by all the Governments that are party to the NEM in the Council of Australian Governments (COAG). The majority of the Guarantee mechanism is implemented through amendments to the National Electricity Law (NEL) and the National Electricity Rules (Rules).

- The NEL will set out who is liable under the emissions reduction and reliability obligations, the key aspects of those obligations, and the compliance and penalty framework. It will also include a new emissions objective to guide rule-making in relation to Rule changes relevant to the emissions reduction requirement.
- Detailed aspects of the mechanism (as set out in the final detailed design document) will be included in the Rules.

The second route of legislation is via the Australian Government. Australian Government legislation sets the intensity targets, provisions for emissions-intensive trade-exposed (EITE) exemptions, the surrender of offsets, and emissions reporting and related information sharing and gathering powers.

The responsibilities of the COAG Energy Council and the Australian Government, as they relate to the Guarantee, are set out as follows.

If the COAG Energy Council approves the final design of the Guarantee at its 10 August 2018 meeting, there will be a period of public consultation on the draft NEL legislation, which is anticipated to occur from around mid-August to around mid-September. It is expected that the draft NEL legislation will then be finalised for introduction to the South Australian Parliament by the end of 2018.

The necessary Rules to implement the Guarantee will be made by the South Australian Energy Minister in mid-2019.

Limited aspects of the operation and implementation of the Guarantee will be reviewed after three years to ensure that it is working smoothly.

After the initial package of changes to the Rules are made, the Australian Energy Market Commission (AEMC) is the rule-maker in response to rule change proposals and in accordance with its current functions under the NEL.

Using an established framework, with clear accountabilities and change processes, will give businesses and investors the confidence and certainty they need to invest in the long-term and deliver cheaper, cleaner and more reliable electricity for Australian consumers.
1 Introduction and next steps
1.1 Background to this paper

On 24 November 2017, the COAG Energy Council requested the ESB provide further advice on the Guarantee.

The ESB’s high-level design for the Guarantee was presented to the 20 April 2018 COAG Energy Council meeting. It was agreed that the ESB would progress development of the detailed design of the Guarantee, for determination at the COAG Energy Council’s 10 August 2018 meeting.

The Guarantee comprises changes to the NEM and its legislative framework which seek to:

- maintain the reliability of the system
- achieve the emissions reductions required from the electricity sector to meet Australia’s overall international commitments, and
- meet the above objectives at the lowest overall costs.

The ESB has benefited greatly from the engagement and feedback from a range of stakeholders on the detailed design of the Guarantee.

- The ESB convened Technical Working Groups to advise on certain detailed design elements. The Technical Working Groups were comprised of a broad range of stakeholders with relevant expertise from more than 30 organisations.
- A stakeholder forum was held in Melbourne on 2 July 2018.
- More than 90 submissions on the consultation paper were received from a range of stakeholders, including a number of retailers, generators, and large energy users.

The ESB thanks stakeholders for their participation in the consultation process.

1.2 Process

Designing the Guarantee has been an iterative and inclusive process. Inception to final design has taken almost a year with input through multiple consultation processes.

The detailed design outlined in this document builds on:

- the model the ESB initially proposed in its November 2017 advice
- the draft design consultation paper published on 15 February 2018
- the high-level design published on 20 April 2018, and
- the draft detailed design released for public consultation on 15 June 2018.

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- More than 90 submissions on the consultation paper were received from a range of stakeholders, including a number of retailers, generators, and large energy users.

The ESB thanks stakeholders for their participation in the consultation process.
Next steps
The COAG Energy Council will be asked to agree to the final design of the Guarantee mechanism at its 10 August 2018 meeting. Subsequently, jurisdictions will be asked to approve the release of an exposure draft of the Bill to amend the NEL. Following a four-week consultation period, the Bill will be finalised for introduction to the South Australian Parliament before the end of 2018. The amendments to the NEL deal with the mechanism of the Guarantee and the way in which reliability and emissions are considered together to achieve the three objectives of affordability, reliability and emissions reduction.

Draft rule changes will be presented to the COAG Energy Council at its April 2019 meeting, after a period of development and consultation. If agreed, these Rules will be made by the South Australian Energy Minister in 2019.

The national emissions target and trajectory from 2020 to 2030, the review points for that target, the process for extending targets, and the treatment of offsets and emissions-intensive trade-exposed industries are matters in the jurisdiction of the Australian Government. These matters are all dealt with separately in Commonwealth legislation, which will be introduced into Parliament if COAG agrees to proceed with the Guarantee.

Some State and Territory governments have, or are proposing, emissions reduction schemes and programs in their jurisdictions. These are matters for those governments and their legislation. If the Guarantee is implemented these schemes will coexist with it.

1.3 Structure of final detailed design paper
This paper is structured as follows:
- Chapter 2 explains the context for and expected outcomes of the Guarantee.
- Chapter 3 describes the ESB’s detailed design for the emissions reduction requirement.
- Chapter 4 describes the ESB’s detailed design for the reliability requirement.
- Chapter 5 outlines the governance approach for the Guarantee.
- Chapter 6 outlines the market modelling undertaken to support the analysis in this paper.

To make it easier to track how the Guarantee has developed, this paper is set out in a similar way to the earlier papers.
2 Context
The Guarantee brings together climate and energy policy for the first time in Australia.

The Guarantee brings together climate and energy policy for the first time in Australia. It ensures we can meet the electricity sector’s share of our international obligation to reduce emissions, while supporting the reliability of our electricity system. Providing long-term policy confidence will lower investment risk in the NEM and bring down electricity prices.

Submissions to the ESB’s consultation process were widely supportive of the objectives and design of the Guarantee.

“The Business Council believes that the Guarantee will put in place a durable mechanism that appropriately balances our economic growth, energy security, and environmental sustainability.” – The Business Council of Australia

“In our view, the importance of acting to rebuild the confidence of consumers in the sector and trust in the energy system cannot be overstated. Consumers understand that there is a generation “supply” problem, with the ageing of the coal fired power station fleet, and the need for a minimum amount of dispatchable energy to be available to meet consumer and system needs, in the transition to a lower emissions economy.” – Energy Consumers Australia

“We are broadly supportive of the proposed National Energy Guarantee design as per the draft detailed design consultation paper. We believe it appropriately addresses stakeholder concerns, while also integrating energy and emissions policy in a way that encourages new investment in clean and low emissions technologies and a dynamic energy market.” – St Vincent de Paul and South Australian Council of Social Service (SACOSS)

“Origin supports the objectives of the NEG to bring together energy and climate change policy and provide a clear investment signal for low emissions and reliable generation sources at least cost to Australian homes and businesses.” – Origin

“When we saw the draft design... we liked what we saw and we decided to invest in more generation on top of the generation we had at that time, so we bought three hydro power stations and entered into a bunch of power purchase agreements to support new build and that has now translated into lower prices for our customers... and we are in discussion with several parties about long-term contracts to support dispatchable power. ...

So the point there is that at least some of the benefit of the NEG is already built in to the forward price and consumers are already starting to see some of the benefit on their bills. So what that means is if the NEG is not approved – I don’t know what’s going to happen, but I think it’s reasonably likely wholesale prices will increase. If wholesale prices increase, we’ll see some reversals of the positive situation we’re in now where we see flat or declining price for consumers in the most recent price changes, and I think that just gets us into a spiral that I don’t think is healthy for anyone.” – Ed McManus, CEO of Powershop Australia, 2 July 2018 stakeholder forum

Context

Fifteen years of climate policy instability has impeded long-term investments in the NEM and this has compromised system security and reliability. It has also impacted electricity prices and added to affordability problems for consumers. As the Finkel Review noted, our energy system has been vulnerable to escalating prices while being both less reliable and secure. Increased market intervention has been necessary to maintain the security and reliability of the system and this has further distorted price signals to producers and consumers. In short, the uncertainty about climate change policy has severely damaged the electricity industry and its household and business consumers. This cannot continue.

The Guarantee brings together climate and energy policy for the first time in Australia. It ensures we can meet the electricity sector’s share of our international obligation to reduce emissions, while supporting the reliability of our electricity system. Providing long-term policy confidence will lower investment risk in the NEM and bring down electricity prices.

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“EnergyAustralia considers that the main barrier to efficient investment in dispatchable capacity has been the policy uncertainty around emissions reduction. If this is resolved through the Guarantee, or another policy, then it will help end the paralyses of decision making that confronts long term investment and divestment decisions for assets worth hundreds of millions of dollars which have lives of 15-20 years or more.”

– EnergyAustralia

2.1 The status quo is not an option

Until recently, almost all of the NEM’s generation was supplied by large thermal generators (coal or gas), or from hydro. Other forms of generation, such as solar or wind power, were not economic without significant subsidies. This is no longer the case. Substantial cost reductions in wind and solar generation have occurred. These cost reductions have been technology driven and have improved with manufacturing scale.

Customer preferences have also changed and encouraged increased deployment of wind and solar PV. Many large-scale solar and wind projects are underpinned by power purchase agreements from Australian businesses – reflecting the attractive electricity costs these agreements can now offer and a preference from some businesses for low emissions electricity. Voluntary action schemes such as GreenPower and State based renewable schemes add to this demand.

Nationally, more than 17 per cent of households have either solar PV or solar hot water or both, with almost 1.9 million small-scale solar PV systems now installed.7

Recent increases in export coal and gas prices have added to the challenges for thermal generators making it more difficult for these technologies to compete. In the last two years thermal coal export prices, for example, have increased from around $73 per tonne to around $115 per tonne,8 and between 2015 and 2018 gas-fired generators’ fuel costs have risen from almost $5 per gigajoule to around $8 per gigajoule.9

These developments have encouraged deployment of renewable generation in the NEM and these trends are expected to continue.

The introduction of solar and wind into the NEM at this scale is a challenge that will require adaptations to the existing framework. The variable nature of wind and solar PV means it cannot be dispatched on demand. This requires complementary capacity that is capable of rapidly increasing or decreasing output in response to changes in system demand or output from wind and solar PV.

Developments in behind the meter technologies including rooftop solar, battery storage and electric vehicle charging are changing the shape of daily demand, resulting in sharper peaks and shallower troughs in average time-of-day demand. This means much sharper increases in output from the grid will be required in the afternoon as demand increases and output from solar PV drops. Over the period to 2030, flexible generation resources that can rapidly ramp up to the evening peak will be critical.

These changes underway in the NEM cannot be reversed. They are now more market driven than policy driven. The operating procedures and rules governing the NEM must also adapt and do so in a coordinated way that supports the transition while ensuring electricity is affordable. An unstable and uncoordinated policy environment exacerbates these issues.

National electricity prices have more than doubled over the past decade – growing much more rapidly than general inflation and lowering the purchasing power of all Australian households, especially the most vulnerable (Chart 1). While much of the price increase over the past 10 years has been caused by network or retail pricing, the more recent increases have been largely attributable to increased wholesale prices. These price increases have also been an impost on Australian businesses, potentially undermining their international competitiveness and weighing on economic growth.

Chart 1: Cumulative increase in the price of Australian consumer goods

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<thead>
<tr>
<th>Year</th>
<th>Cumulative percentage increase in nominal prices</th>
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<tbody>
<tr>
<td>Mar 08</td>
<td>0</td>
</tr>
<tr>
<td>Mar 10</td>
<td>10</td>
</tr>
<tr>
<td>Mar 12</td>
<td>20</td>
</tr>
<tr>
<td>Mar 14</td>
<td>30</td>
</tr>
<tr>
<td>Mar 16</td>
<td>40</td>
</tr>
<tr>
<td>Mar 18</td>
<td>50</td>
</tr>
</tbody>
</table>

Source: Australian Bureau of Statistics, Catalogue Number 6401.07

7 Clean Energy Regulator Postcode data for small-scale installations and ABS 6523.0 - Household Income and Wealth, Australia, 2015-16.
8 Resources and Energy Quarterly – June 2018, Department of Industry, Innovation and Science.
The Australian Competition and Consumer Commission’s (ACCC) recently released Retail Electricity Pricing Inquiry—Final Report is a comprehensive study into the drivers of retail electricity prices with a wide-ranging package of recommendations to reduce prices. The ESB welcomes this report and looks forward to working with the COAG Energy Council to consider how these recommendations are best responded to and implemented. A cornerstone of the ACCC’s recommendations to reduce wholesale electricity prices is the adoption and implementation of the Guarantee.

Lowest cost outcomes for consumers will be achieved by creating a stable policy environment which appropriately values an optimal mix of capacity and creates clear incentives for the private sector to deliver it.

2.2 Longer term price signals at the heart of the Guarantee

Spot market prices for electricity are for the very near-term, that is, the next 30 minutes. In contrast, the agreements struck between retailers and generators in the contract market have a much longer-time horizon, sometimes spanning many years.

The Guarantee addresses the market for wholesale electricity contracts. Derived from market expectations of future spot prices, these contract markets focus on the longer term and deliver key signals for new investment.

The NEM is designed so that price signals provide the necessary information for market participants to make investment or retirement decisions concerning their physical assets and their efficient operation. These price signals are borne out in wholesale spot market outcomes and financial contract markets, both of which provide participants with strong incentives to deliver electricity when it is needed. If participants fail to manage their financial exposure to either low or high spot prices or make a poor investment decision (for example, in a new generator that is under utilised), they alone face the financial consequences, not consumers or taxpayers.

The Guarantee builds on the existing pricing and risk management frameworks used in the NEM to signal the need for investment in new sources of generation.

Market participants are expected to contract in a variety of ways to meet both the emissions reduction and reliability requirements. Through their contracting, market customers will support a range of different generation and demand-side technologies. This will result in increased contracting levels, which in turn will create deeper and more liquid contract markets.

Increased contracting in deeper and more liquid contract markets is expected to reduce the level and volatility of spot prices.

The Guarantee has been specifically designed to ensure it does not undermine but rather enhances the liquidity, transparency and the level of competition in the retail and wholesale electricity markets.

2.3 Reducing electricity prices and improving affordability

In the advice presented to the COAG Energy Council in November 2017, the ESB included initial estimates of the effects of the Guarantee based on detailed market modelling.

This section presents updated estimates of the effects of the Guarantee, reflecting the final policy design as well as developments in the NEM over the past nine months. The updated modelling results are detailed further in Chapter 6.

Current high wholesale electricity prices, as well as the Australian Government’s Renewable Energy Target (RET) scheme, have incentivised a large pipeline of renewable generation. Already committed projects and the first stages of the Victorian Renewable Energy Target (VRET) and Queensland Renewable Energy Target (QRET) schemes means that around 7,800 MW of large-scale wind, solar and battery capacity is expected to be added to the NEM between 2018-19 and 2020-21.

But a failure, again, to agree and implement an integrated energy and climate policy will be disruptive and could result in a continued and potentially extended environment of policy uncertainty. In this environment, it is reasonable to assume that only those projects currently financially committed would proceed to build. In an environment of continued policy uncertainty, it is also reasonable to assume that financing costs and the associated hurdle for new investment will be higher than under the Guarantee.

Chart 2 outlines the expected build profile over the years to 2030 should the Guarantee not proceed. Only new-build projects that have reached financial close or that will be funded under Stage 1 of the VRET or QRET are expected to be constructed in the short-term. The Australian Government’s Snowy 2.0 project is anticipated to commence generation in 2023-24. Some black coal generation is expected to withdraw in line with announced closures or key contracting and technical milestones. Rooftop solar PV is expected to continue to expand through to 2030 in line with AEMO forecasts.

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11 This estimate is consistent with the ESB’s market intelligence and supported by stakeholder submissions to the policy development process, see for example the Powershop and EnergyAustralia comments published at the beginning of this chapter.
The Guarantee will provide stakeholders with policy confidence by comprehensively integrating energy and climate policy to guide an orderly transition for the electricity sector.

The continued connection of additional renewable generation projects to the NEM in coming years is projected to see prices fall from today’s elevated levels (Chart 3). The modelled short-term wholesale price reductions are comparable to those currently implied by futures contracts.

While the closure (as announced) of the Liddell coal-fired power plant in NSW in 2022-23 puts some upwards pressure on prices, in NSW in particular, the addition of around 2,000 MW of capacity with the completion of the Australian Government’s Snowy 2.0 pumped hydro project in 2023-24 is expected to extend this period of lower prices. However, prices are expected to rise again over the decade as the supply-demand balance tightens and real gas prices are assumed to rise. Little further investment is required before 2030 under this scenario which assumes no unexpected closures of major thermal plant. There is a further slight increase in the price trajectory in 2029-30 associated with the modelled withdrawal of some black coal capacity in Queensland.

The Guarantee will lower prices in five key ways:

- policy stability unlocking new investment
- policy stability reducing the risk [and therefore the cost] of new investments
- increased contracting unlocking new investment
- contract markets becoming deeper and more liquid and reducing the level and volatility of spot prices, and
- increased voluntary demand response.

The Guarantee will provide stakeholders with policy confidence by comprehensively integrating energy and climate policy to guide an orderly transition for the electricity sector. This will assist in bringing forward additional new investment and reduce the cost of capital of those new investments.
Through their contracting, retailers will support a range of different generation and demand-side technologies to meet the emissions reduction and reliability requirements of the Guarantee at the lowest possible cost.

Increased long-term contracting is expected to further lower prices under the Guarantee as all market customers (mostly retailers) will be required to have a reliable level of firm contracts in place at key times. This will lead to more competitive bidding in the spot market as generators reduce their bids to increase their chances of being dispatched to cover their contracted capacity.\(^\text{12}\) Generators with high levels of long-term contracts in place face strong financial incentives to be able to generate in contracted time-periods. In this way, higher levels of long-term contract cover also slightly mitigate the risk of short-notice generator closure.

The incentives and structures created by the Guarantee are also expected to accelerate the development of the demand-side response market. This will give the NEM additional, potentially-lower cost, ways to respond to peaks in demand.

In aggregate these aspects of the Guarantee are expected to place significant additional downwards pressure on prices. NEM-average wholesale prices are, on average, expected to be over 20 per cent lower over the 2020s under the Guarantee than without it (Chart 4).

Lower wholesale prices are expected to lower bills for all consumers. The average NEM-connected household is estimated to save around $550 dollars a year (real $2018) on their retail bill over the 2020s relative to 2017-18 with network costs held constant in real terms. Of this, nearly $150 per year (real $2018) of projected savings is directly attributable to the Guarantee (Chart 5).

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\(^\text{12}\) A generator typically offers contracted capacity at marginal cost (save for below marginal cost bids in respect of a minimum level of generation required to safely continue operation) and offers remaining capacity to maximise net revenues.
The price savings from the Guarantee are expected to be broad-based, with all NEM jurisdictions expected to benefit from lower electricity prices as a result of the Guarantee. These savings are not directly comparable with the estimated bill savings in the ACCC’s recent Retail Electricity Pricing Inquiry—Final Report – the estimated savings differ in scope and the time periods compared.

Wholesale prices are projected to fall in all NEM jurisdictions relative to 2017-18. Additional committed supply and moderation in coal prices are projected to put downwards pressure on prices even without the Guarantee (Chart 6). The closure (as announced) of the Liddell coal-fired power plant in NSW in 2022-23 puts some upward pressure on prices particularly in NSW. However, the replacement capacity announced by the ownership of Liddell together with the addition of around 2,000 MW of capacity with the completion of the Snowy 2.0 pumped hydro project in 2023-24 is projected to put further downward pressure on prices, broadly offsetting the price effects of Liddell retiring and extending a period of lower prices. Some Queensland black coal generation is projected to withdraw in line with key contracting and technical milestones around 2029-30 which causes a further slight increase in the modelled wholesale price trajectory in Queensland at this time. The modelling suggests that under this scenario, it will not be profitable for some Queensland black coal capacity to undergo necessary refurbishments in 2029-30, a time which coincides with the expiration of a major power purchase agreement. However, the modelling does not consider the potential for particular commercial arrangements to be extended or assess the additional value that the flexibility of this type of plant might attract. As with any modelling, particularly over such long time horizons, this should not be read as a prediction of future events.

Chart 6: Wholesale regional reference prices without the Guarantee

Source: ACIL Allen consulting
Wholesale prices are forecast to be lower in all NEM jurisdictions under the Guarantee than in its absence (Chart 7).

**Chart 7: Projected jurisdictional wholesale price outcomes**

<table>
<thead>
<tr>
<th></th>
<th>New South Wales</th>
<th>Queensland</th>
<th>South Australia</th>
<th>Tasmania</th>
<th>Victoria</th>
<th>NEM</th>
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<tr>
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</tbody>
</table>

Source: ACIL Allen consulting
A portfolio of resources is required so that when wind and solar are not available, alternative sources of power can be dispatched.

2.4 Managing reliability risks

The reduction in dispatchable coal-fired generation and the greater penetration of variable renewable technologies such as solar and wind generation present risks to the reliability of our electricity supply.

Historically, most of the installed generation capacity has been dispatchable (that is, able to generate as required) provided by coal, gas and hydro-electric plants. Provided these generating units have sufficient fuel (that is, coal, gas, stored water) and their operational positions allow it – and assuming no unexpected outages or transmission constraints – they can be called upon by AEMO to increase or decrease their output at any time in a predictable manner, given enough notice.

However, as Australia’s ageing generators retire they are being replaced by cheaper variable renewable alternatives or increased output from gas-fired power stations.

The proportion of available dispatchable generation capacity in the NEM is therefore declining. While some new wind and solar investments in Australia are seeking to make themselves dispatchable by co-locating with a battery or storage such as pumped hydro, this is not true for the majority of these resources. Therefore, a portfolio of resources is required so that when wind and solar are not available, alternative sources of power can be dispatched.

The reliability requirement is designed to ensure that a portfolio of dispatchable power is available when required as the system transitions. Increased contracting will also reduce the likelihood of unexpected closures. For generators, greater levels of contracting will have the effect of increasing their commitment to future generation – as a failure to generate at times they are contracted would leave them exposed to significant financial risk. Transferring such liabilities is costly, and so being in a largely contracted position would increase a generator’s incentive to keep the plant well-maintained and to quickly take action to respond to any unplanned outages. The reliability requirement is expected to work in combination with the three-year notice of closure rule recommended by the Finkel Review to ensure market decisions are made in a more orderly fashion.13

The Guarantee also incentivises a more developed demand response market, financially rewarding action by consumers, which will aid reliability and capture value for consumers who choose to participate.

Neither the risk nor the effects of unanticipated outages or closures should be underestimated, especially as the share of dispatchable generation in the NEM decreases. Without the Guarantee, the market will have a less coordinated response to unanticipated events, and such disruptions could increase prices and threaten reliability as has been seen over the past few years.

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13 The Finkel Review recommended that generators in the NEM be required to give at least three years’ notice to the market prior to closure to support an orderly transition. The COAG Energy Council endorsed this recommendation on 14 July 2017 and the rule change request is currently being considered by the AEMC: https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.
Case study: The closure of the Northern Power station in South Australia

The Northern Power Station (Northern) was a 540 MW coal fired generator located near Port Augusta in South Australia that had historically provided up to 40 per cent of the region’s electricity. In October 2015, Alinta announced it would be closing Northern in just five months’ time, bringing forward the closure date by two years, due to an increasingly challenging operating environment and failure to secure support to remain open.

At the time of its retirement, Northern was over 30 years old, though not yet at the end of its operational life. However, the mine that supplied the power station was running out of quality coal and the mine would have required significant capital-intensive augmentation to continue operation. Over the previous four and half years, Alinta had reportedly invested $200 million to extend the operating life of the generator. The key reasons for the difficult trading conditions faced by Northern included reduced electricity demand (partly driven by the uptake of rooftop solar PV) and increased competition from zero marginal cost variable renewable energy generation in South Australia.

Prior to the closure, Alinta was reportedly seeking to secure customers (particularly commercial and industrial users) via long-term energy off-take agreements for the coming years to ensure Northern’s continued operation. The prices sought for these contracts, while likely higher than what commercial and industrial users were expecting to pay if they had otherwise remained exposed to the wholesale spot price, look very good value in hindsight.

The closure of Northern in May 2016 resulted in a substantial reduction in supply in energy and ancillary service markets, and in contract market liquidity in South Australia. Contributing factors to these increased wholesale prices included a greater reliance on gas generators at a time when gas prices were increasing on the east coast, interconnector constraints, as well as limited availability of existing gas-fired generators due to mothballing. Had Northern successfully secured customers via long-term contracts, it is likely that it would have continued to operate through 2016 and 2017.

Following the closure of Northern, the majority of new generation capacity constructed in South Australia has been variable renewable energy. As variable renewable energy traditionally does not offer firm contract products, this has not improved contract liquidity in the region.

Counterfactual scenario

Drawing on AEMO’s observation in its Integrated System Plan that a key element of a least cost approach to support an orderly transition of the energy system sees coal generators maintained until the end of their technical lives, a counterfactual scenario was modelled where Northern continues operating beyond May 2016 to assess the potential wholesale price outcomes.

The Guarantee is intended to increase long-term contracting and help lessen the likelihood of unexpected sudden and early exits, where reliability is identified to be at risk. Increased contracting will incentivise generators to defend their sold contract positions or face significant financial liabilities. The reliability obligation will reinforce the value of firm contracts in times and regions when supply of these contracts is at risk of becoming scarce.

The modelled price outcomes over the period May 2016 to December 2017 suggest that wholesale prices would have been materially lower than those observed over the period. This is particularly evident in the winter of 2016, where a series of high price events significantly drove up average wholesale spot prices, and in the first half of 2017 where the supply-demand balance was very tight. The average wholesale price in the counterfactual scenario is around $79/MWh compared with the actual price observed of $102/MWh (representing a 23 per cent reduction) [Chart 8].
The Guarantee can also accommodate different levels of ambition over time, and work with State and Territory schemes to create greater confidence for the industry.

2.5 Reducing emissions

The Australian Government has proposed to set an emissions reduction target for the electricity sector consistent with achieving a 26 per cent reduction on 2005 levels by 2030.

The currently committed pipeline of new renewable generation is expected to make a substantial contribution to lowering emissions in the NEM and the amount of additional abatement required. Annual NEM emissions are expected to fall by over 15 MtCO₂-e between 2017-18 and 2020-21 reflecting the significant volume of renewable energy committed to connect to the NEM over this period. By 2020-21, emissions in the NEM are expected to be around 24 per cent below 2005 levels.

But without a specific policy commitment to achieve emissions reductions in the NEM, it is expected that cumulative emissions over the decade will not reduce enough for the NEM to meet its share of the national target (Chart 9).

The emissions reduction requirement is designed to ensure that the NEM evolves in a manner that is consistent with the undertakings given by Australia under the Paris Agreement. The Guarantee can also accommodate different levels of ambition over time, and work with State and Territory schemes to create greater confidence for the industry.

The Guarantee is expected to deliver the emissions reduction target for the NEM, with an additional 38 MtCO₂-e abatement over 2020-21 to 2029-30 relative to a scenario without the Guarantee. The flexibility allowed by the carrying forward of over-achievement and deferral between years will assist in lowering overall abatement costs.¹⁴

¹⁴ The modelling imposed a cumulative target for 2020-21 to 2029-2030 of around 1,320 MtCO₂-e, consistent with the NEM achieving a 26 per cent reduction on its historical 2005 emissions.
The Guarantee has therefore been specifically designed to not undermine, and may indeed boost, competition through measures that enhance market liquidity and pricing transparency in retail and wholesale electricity markets.

Operation of the Guarantee under higher emissions reduction targets
It is possible that higher emissions reduction targets (that is, a larger percentage reduction in emissions) may be set in the future by the Australian Government. This would require a change to Australian Government legislation. However, the Guarantee framework will automatically accommodate new targets. In particular, no changes to the NEL are expected to be required based on the proposed drafting.

Higher targets create greater demand for lower emissions intensity allocations under the emissions reduction requirement, providing investment signals for existing and new low emissions intensity generators, but will not change the fundamental operation of the Guarantee. The strong disincentives against non-compliance, including a penalty of up to $100 million, allow the design to accommodate more stringent targets and ensure that market participants respond effectively to the investment signals provided by the Guarantee.

Depending on the magnitude and timing of any changes to targets, consideration could be given to adjusting some parameters of the emissions reduction requirement, such as the limit on carrying forward over-achievement or deferring under-achievement. However, these are parameters that can be changed in the Rules; the NEL itself would not need any changes.

In the absence of a policy such as the Guarantee that takes into account both emissions and reliability, higher targets could mean an increase in the share of variable renewable generation to a point where reliability becomes an issue. However, under the Guarantee, the reliability requirement ensures that firm capacity (including demand response) is contracted by liable entities. This will incentivise investment in dispatchable resources so that higher targets do not impact on reliability.

Interaction of the Guarantee with state targets
A number of State and Territory governments have, or have proposed, renewable energy targets for their region. Projects developed under a state-based scheme would also be eligible to transfer their allocations to a market customer for the purposes of complying with the emissions reduction requirement. These projects would therefore contribute to achieving the NEM-wide emissions intensity target set by the Australian Government.

However, there is nothing within the design of the Guarantee which limits the ability of states to set and meet their own emissions reduction or renewable energy targets.

In regions with both the Guarantee and a state target operating, some of the beyond business-as-usual investment would be driven by both policies supplementing each other. One of the two policies will bind to deliver more additional investment and emissions reductions than the other.

The Guarantee does not require any region to deliver a specified level of emissions reductions or renewable investments to achieve the NEM-wide emissions reduction target. Instead, the Guarantee creates the incentives for investors to find the most efficient locations to invest across the NEM to deliver a given emissions reduction target. This is reinforced by the reliability requirement that, regardless of the change in generation mix, preserves reliability in each region. Emissions reduction or renewable energy goals within a jurisdiction will contribute to achieving the NEM-wide emissions reduction target, but there is no mechanism to increase the target for other jurisdictions in light of individual state and territory goals.
2.6 Safeguarding competition

In 2017, the Finkel Review highlighted concerns about wholesale market competition and increased retail and wholesale market concentration, and the implications for price and service outcomes. As noted above, the ACCC has also considered issues of market concentration as part of its Retail Electricity Pricing Inquiry—Final Report and made a number of key recommendations.

Stakeholders have been clear in their engagement with the ESB that competition cannot be undermined through the design of the Guarantee. The Guarantee has therefore been specifically designed to not undermine, and may indeed boost, competition through measures that enhance market liquidity and pricing transparency in retail and wholesale electricity markets.

The Guarantee will safeguard competition in five key ways:

- The emissions registry will support contract market liquidity by not requiring bespoke, physically linked financial contracts.
- Limits will be applied on carrying forward over-achievement in the emissions registry to prevent hoarding but with greater flexibility for smaller retailers.
- The emissions registry will automatically correct over-allocations of generation, to prevent hoarding and to make sure that all retailers will be able to comply.
- 50,000 MWh exemption from registry compliance to support smaller retailers.
- Market Liquidity Obligation (when the reliability obligation is triggered) to ensure largest participants must offer to buy and sell contracts with all participants. This will be supported by a voluntary book-build conducted by AEMO.

3 Emissions reduction requirement
An emissions registry will allow market customers to be allocated a share of a generator’s output and its associated emissions, for which they have obtained the rights. The registry automatically matches emissions to each market customer based on the generation allocated against their load. Unallocated load is assigned the average emissions intensity of all unallocated generation in the registry.

The AER will compare each market customer’s average emissions intensity against the electricity emissions intensity target to assess compliance.

This chapter sets out details of the emissions reduction requirement, including:

- coverage of market customers and their load
- the approach to allocating generation and associated emissions, matching generation and load, and registry operations
- flexible compliance options and the rules governing their use, and
- the framework for the AER to monitor and enforce compliance.

3.1 Electricity emissions intensity targets

The Australian Government has consulted on its proposed design of the Commonwealth elements of the emissions reduction requirement, including its approach to setting the electricity emissions intensity targets, implementing the exemption for EITE activities, and the use of external offsets.

The Australian Government will legislate the trajectory of annual emissions targets for the electricity sector, expressed as average emissions per MWh (‘electricity emissions intensity targets’). The NEL will refer to these electricity emissions intensity targets for the purpose of the emissions reduction requirement.

3.2 Entities covered by the emissions reduction requirement

Entities subject to the emissions reduction requirement will be each entity registered by AEMO as a market customer under the Rules (mostly retailers, but also other parties that purchase electricity directly from the NEM).

Each market customer will manage its own reporting and compliance. To allow one company within a corporate group to manage reporting and compliance for multiple market customers, there will be an ability for a market customer’s obligation to be transferred to another related market customer, if agreed by both parties.

The market customer’s performance against the electricity emissions intensity target is determined as the average emissions associated with its generator allocations from the registry, per MWh of its load.

A market customer’s load for the purpose of the emissions reduction requirement includes adjustments to account for the following circumstances.

- **Small market customer exemption:** To support retail market competition, the first 50,000 MWh of a market customer’s load is exempt from the emissions reduction requirement. The exemption will apply to one market customer per corporate group. The level of the exemption has been set such that small market customers will be exempt for some or all of their load. As a market customer’s load increases above 50,000 MWh, its exempt proportion decreases. This measure will help smaller market customers meet the emissions reduction requirement, while not affecting overall coverage. So that the electricity emissions...
The emissions reduction requirement is designed to ensure there is sufficient flexibility for market customers to meet their compliance obligation at lowest possible cost.

3.3 Applying the emissions reduction requirement

The emissions reduction requirement is designed to ensure there is sufficient flexibility for market customers to meet their compliance obligation at lowest possible cost. An emissions registry is used to allocate generator output and its associated emissions to a market customer’s load for each compliance period. This can be based on any contractual arrangement held with a counterparty outside the registry, provided both the market customer and the generator verify the agreement in the registry. Market customers can agree to enter into contracts to allocate generation in the registry with the same generators that they enter into hedging contracts with, but there is no requirement for these parties to be the same. This will ensure that the Guarantee works in a way that is integrated with existing electricity market operations without compromising financial market liquidity.

The emissions reduction requirement has been designed as a whole-of-market mechanism, in that every MWh of generation that occurs in a compliance year will be recorded in the registry for allocation against every MWh of market customer load in that compliance year. This will include the exports from rooftop solar PV and other embedded generation as purchased by market customers.

Inclusion of pre-1997 renewable generation

The draft detailed design consultation paper noted the view of some stakeholders that pre-1997 renewable generation that is not included in the RET – for example, the majority of Australia’s hydro generation – should not benefit from the emissions reduction requirement. This could mean excluding this generation and its associated emissions from the emissions reduction requirement altogether, or alternatively, automatically distributing it between market customers.

In its submission to the consultation process, ENGIE in Australia & New Zealand acknowledged the additional complexity that may entail from excluding pre-1997 renewable generation, but raised concerns that “its inclusion may result in inappropriate wealth transfers or place large renewables portfolios in a significantly advantageous position”. EnergyAustralia similarly expressed a position that “pre-1997 renewable generation should be baselined out of the Guarantee as they were for the Renewable Energy Target, to avoid significant windfall gains”. However, a number of submissions to the consultation process supported the inclusion of the pre-1997 renewable generation in the emissions reduction requirement. The Australian Industry Group suggested that under the emissions reduction requirement “every source of generation has an underlying value or disvalue for achieving the target. Attempting to excise this value as a ‘windfall gain’ risks overcomplicating the scheme and discouraging efficient decisions about the use or extension of old assets.”

BlueScope Steel noted that the inclusion of the pre-1997 renewable generation “provides for a broader range of compliance options for liable entities. It also simplifies compliance and target setting under the Guarantee.” Delta Electricity’s view was that excluding pre-1997 renewable generation “could also exacerbate competition concerns for smaller market participants by denying them access to the widest range of sources of low emissions generation.”

The large hydro generators were opposed to excluding pre-1997 renewable generation: “Any proposal to exclude pre-1997 generation would violate competition and technology neutrality principles, would be detrimental to retail competition, and would not incentivise hydro generation to provide energy services such as system strength and inertia as the NEM transitions to a renewable and intermittent generation mix.” – Snowy Hydro

“The Guarantee has been designed as a technology-neutral mechanism that applies to the whole market so that it can achieve emissions reductions at least-cost. To record the allocation of generation in the registry, it must be requested by one party, and approved by the counterparty. The parties can record allocations at any time during the compliance period. They will also have nearly six months after the end of the compliance period to continue to adjust their portfolios by recording reallocations, until the compliance deadline of mid-December.

The pool of unallocated generation and emissions in the registry will have an associated ‘residual’ emissions intensity. The residual emissions intensity will be a floating value, which varies over the compliance period as allocations are recorded. Market customers that do not have generation allocated for some, or all, of their load by the end of the compliance and reporting period will be assigned the residual emissions intensity for that load.

Allocations will be expected to be entered in a timely manner to allow AEMO to provide regular updates of the contents of the unallocated pool and its emissions intensity.

Incentives for allocating generation

The draft detailed design proposed an administrative requirement that generators allocate all generation and associated emissions by the reporting and compliance date.

Through the consultation process, several stakeholders provided feedback that a requirement of this nature is not necessary for the emissions reduction requirement to operate effectively, and should be removed.

“Delta does not believe that the administrative obligation on generators to allocate all their generation in the registry is necessary for the operation of the emissions obligation.” – Delta Electricity

Alinta expressed a concern that the proposed requirement “creates a potential risk on generators, whereby if they are unable to assign their allocation to a liable entity they will be penalised”, while the Minerals Council of Australia contended it would “increase costs and reduce incentives for investment in existing dispatchable generation” and the Australian Aluminium Council similarly expressed a concern that it “may undermine the business model of dispatchable (thermal) generation and that generation is needed to undertake any transition effectively.”

25 It is not intended that output could be directly allocated between generators.
On the other hand, the Australian Industry Group considered the proposed requirement as being “reasonable to help ensure that market customers have full opportunity to acquire the generation volumes they require to comply” and ERM Power raised a concern that the absence of such a requirement “would allow vertically-integrated gentailers to push the costs of high-emissions generation onto their competitors”.

The ESB has decided not to proceed with the requirement that generators allocate all generation and associated emissions. On balance, it is considered the final design contains sufficient incentives for efficient allocations from generators to market customers, including by providing visibility over the volume of unallocated generation and its average emissions intensity.

The draft detailed design also proposed a legal requirement that market customers and generators do not unreasonably withhold any allocations for anti-competitive purposes. The ESB has also decided not to proceed with that requirement, as explained in section 3.5.3.

**Over-allocation**

Over-allocation describes a circumstance where the total volume of generation allocated to a market customer exceeds its load in the registry. This is distinct from over-achievement where the generation may match the market customer’s load but the emissions intensity is less than the electricity emissions intensity target.

Since total generation must equal total load in the registry for each compliance period, the consequence of a market customer being over-allocated for the compliance period would be that another market customer will not have sufficient generation (either allocated or from the residual unallocated generation pool) to cover its load.

There is a risk that market customers may unintentionally be over-allocated due to over-estimating their load. While market customers will be able to reasonably estimate their load during a compliance year, they will not know their final load until after mid-November. Once their final load is known, market customers will have one month to adjust their allocations in the registry. A market customer that is over-allocated will have the opportunity to reallocate its excess allocation to another market customer. However, if the market customer does not reallocate, the market customer will remain over-allocated at the compliance deadline.

In the event that a market customer has an over-allocation of generation against its load after the compliance deadline of mid-December, the registry will automatically return the over-allocated generation and associated emissions to the residual unallocated generation pool.

- The generation returned to the residual unallocated generation pool will be the lowest emissions intensity generation allocated to the market customer, up to the volume of over-allocation. For example, a market customer that is over-allocated by 1,000 MWh would have its lowest emissions intensity 1,000 MWh of generation returned to the residual unallocated generation pool.

- The market customer’s compliance against the emissions reduction requirement would then be assessed based on its remaining generation (which would equal its load) and associated emissions.

- This approach will reduce the average emissions intensity of the residual unallocated generation pool, to the benefit of market customers that did not or could not allocate generation against their entire load.

These design elements are intentionally made, to incentivise over-allocated market customers to reallocate their over-allocation to other (under-allocated) market customers, thereby alleviating any competition concerns that might arise from some market customers choosing to remain over-allocated to increase other market customers’ costs of complying with the Guarantee (including any penalties levied on non-compliance).

The draft detailed design proposed an approach to over-allocation whereby the market customer would have been assigned a deemed emissions intensity for the over-allocated amount and would also have faced a civil penalty. Through the consultation process, some stakeholders raised concerns that the proposed approach was too severe, given the possibility that over-allocation could occur unintentionally. The ESB has taken this feedback on board in revising the approach to over-allocation, and has removed the proposed civil penalty for over-allocation. The revised approach is still expected to incentivise market customers to reallocate generation in advance of the reporting deadline to avoid being over-allocated, and provide proportionate treatment to circumstances of unintentional over-allocation.

**3.3.2 Accounting for generation and load**

Total generation in the registry will be calculated as NEM pool generation from AEMO, plus exports from embedded generation including exports from rooftop solar PV. Since emissions reductions achieved by embedded generation contribute to the overall emissions reduction target, such generation ought to be recognised in

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32 As set out in section 3.3.3, mid-November is the deadline for recording embedded generation and solar PV data in the registry (which is used to determine a market customer’s final load)
33 This is generation that is not explicitly part of the NEM (i.e. is non-market) and is either embedded within a local retailer’s host region or embedded behind the meter at a site.
the registry and therefore embedded generator exports are added to pool generation in the registry.

Total load in the registry will be calculated as NEM pool purchases from AEMO, plus load equal to the exports from embedded generation. It will also incorporate adjustments for exempt loads and account for voluntary GreenPower load.

**Pool generation and pool purchases**

Pool generation and pool purchases refer to generation and load that is settled by AEMO through the wholesale market in the NEM. For the purpose of the emissions reduction requirement, all pool generation and pool purchases will be defined ‘at the node’:

- Pool generation is measured at the transmission node identifier, with generator imports netted against exports, and then adjusted by the marginal loss factor.
- Pool purchases are measured by applying transmission and distribution loss factors to the metered volumes.

This approach ensures that the pool generation and pool purchases will require minimal scaling to match (estimated to be within around 1 per cent), improving the accuracy of the registry.

For grid-connected batteries and pumped hydro facilities that are registered in the NEM as both a market generator and a market customer, their exports will be netted against their imports, such that only their net pool purchases are included in their load.

**Embedded generation**

Exports to the grid from embedded generation (including rooftop solar PV) are entered into the registry by the market customer that purchases the output. So that total generation matches total load in the registry, the registry will automatically add the same volume to the market customer’s load.

- The amount of embedded generation entered into the registry will be grossed up to the node by applying transmission and distribution loss factors.
- Embedded generators will be explicitly identified and included in the registry if they exceed both a capacity threshold of 5 MW and have annual emissions of 25,000 tCO₂-e34 or more. These embedded generators will generally already be reporting under the National Greenhouse and Energy Reporting (NGER) scheme. Embedded generators over 5 MW but with emissions below 25,000 tCO₂-e who are not already reporting under NGER will also need to have an emissions intensity determined for the purposes of the Guarantee. The Commonwealth will make provision for the Clean Energy Regulator to determine this through a legislative instrument under the National Greenhouse and Energy Reporting Act 2007.

- Embedded generators below these thresholds will not be individually recorded but will be included in the market customer’s registry account in aggregate and will be assumed for simplicity to have a zero emissions intensity.

The market customer will be able to reallocate the generation and associated emissions from its embedded generators to other market customers, if it chooses. This will be provided for in the Rules in relation to the registry.

Where a market customer is wholly exempt from the emissions reduction requirement as a result of their exempt load, they will not be required to include their embedded generation or solar PV exports in the registry.

With the continued growth of embedded generation and distributed energy resources such as rooftop solar PV and behind the meter batteries, it is likely that AEMO’s future power system planning and operations will require more data about the output from these resources. When this information becomes available to AEMO with greater timeliness and accuracy then it may be possible to integrate distributed energy resources more seamlessly into the registry. However, the timing of any such change will also need to consider how the Commonwealth is setting electricity emissions intensity targets, to ensure that targets and compliance are calculated on a like-for-like basis. The treatment of embedded generation in the registry can be further developed through rule-making processes.

**Exempt load**

The calculation of market customer load will include adjustments for exempt loads, being EITE load, and the first 50,000 MWh of any market customer’s load (the small market customer exemption), as was discussed in section 3.2.

The adjustments will only apply to a market customer’s pool purchases. The ESB considers that the alternative approach of scaling the market customer’s final load (including embedded generation and solar PV) would create too much uncertainty, as the scaling factor would not be finalised until after all market customers had recorded their embedded generation and solar PV loads in the registry.35 No information is available throughout the year to enable updated estimates.

To give effect to the exemptions, each market customer’s pool purchases will be reduced by the 50,000 MWh threshold and by any EITE load it supplies in a compliance year. Across all market customers, each MWh of non-EITE load above the 50,000 MWh threshold will then be scaled-up by a factor such that total load equals the total pool generation.36

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34 To avoid capturing back-up plant that rarely runs.
35 As set out in section 3.3.3, the deadline for recording embedded generation and solar PV data in the registry is mid-November.
36 This methodology also implicitly incorporates the scaling-up of pool purchases to match pool generation.
The registry provides the necessary infrastructure to facilitate efficient compliance with the emissions reduction requirement. The scaling factor will be calculated three months after the end of the compliance year, based on the ratio of total pool generation to total non-EITE pool purchases above the 50,000 MWh threshold, in that year. To provide market customers with greater certainty, the scaling factor will be capped at a maximum based on AEMO’s assessment of the relationship between pool generation and pool purchases, the expected level of EITE load and the number of market customers who will receive the 50,000 MWh exemption in the forthcoming compliance year. The maximum scaling factor will be set using AEMO’s best estimate with a small buffer for error, as the cap should not bind frequently. Throughout the compliance year AEMO will publish the year-to-date scaling factor — based on a conservative high estimate of EITE load as measured at the National Metering Identifier — so that market customers have an indication of how the scaling factor is tracking.

Example of calculating scaling factor and applying to market customer load

Hypothetically:

- The total pool purchase load in a compliance year is 190 TWh. Of this, the exempt load is 30 TWh, which is the sum of:
  - The first 50,000 MWh of each market customer’s load, totalling 2.5 TWh.
  - A total EITE load of 27.5 TWh.

- The total pool generation in the compliance year is 200 TWh. The scaling factor for the compliance year is capped by AEMO at a maximum of 1.3. The final scaling factor is 1.25, calculated as 200 TWh ÷ [190 TWh - 30 TWh]

For a particular market customer with pool purchases of 12 TWh and 1.95 TWh of EITE load:

- Its exempt load = 2 TWh (including its 50,000 MWh exemption plus the 1.95 TWh EITE load)
- Its scaled-up load = 12.5 TWh, calculated as [12 TWh - 2 TWh] x 1.25
- The market customer will have 12.5 TWh of load that will need to have generation matched against it in the registry so that the average emissions level is at, or below, the electricity emissions intensity target (even though the market customer’s actual pool purchases were 12 TWh and it had 2 TWh of exempt load).

GreenPower load

Some businesses and household consumers undertake voluntary action to reduce emissions associated with their electricity use. A prominent example is the GreenPower program. Stakeholders were broadly supportive of ensuring the additionality of voluntary action through the GreenPower scheme. For example, Origin noted that “it is important that the additionality of voluntary offerings is maintained so that retailers can continue to offer new products as the market evolves.”

In a submission on the draft detailed design consultation paper, the National GreenPower® Accreditation Program expressed its support for the proposed treatment of GreenPower and noted their intention to work with the ESB and contribute to the framework of the emissions reduction requirement.

The calculation of a market customer’s emissions intensity will include an adjustment for GreenPower to allow consumers to make an additional contribution to emissions reduction beyond that required by the target. This will be achieved by deducting a market customer’s GreenPower load and associated renewable generation occurring in the compliance year from both its total load and allocated generation. This will mean GreenPower generation does not contribute to a market customer’s emissions intensity for its non-GreenPower load. Market customers will need to have allocated generation from sources that are consistent with its GreenPower product commitment, such as 100 per cent new wind.

Similar to the approach for pool purchases, the GreenPower load will be adjusted by transmission and distribution loss factors.
The registry will be administered by AEMO, which already holds most of the data relevant for the registry’s operation – in particular, pool generation and wholesale pool purchases. It also has some existing data exchange protocols in place with the Clean Energy Regulator. As the registry administrator, AEMO’s responsibilities will include developing detailed procedures for interacting with the registry and managing IT requirements. The AER will have access to the registry to facilitate its role in monitoring and enforcing compliance.

Market customers and generators will have accounts in the registry to manage their allocations. Account holders will only be able to view information relevant to their own account and allocations.

Through the consultation process, stakeholders raised two separate issues in relation to third party access to the registry: access to information, and access to registry accounts.

Access to information

Stakeholders put forward a range of views on the amount and type of information that should be made available.

“To help ensure transparency in the market, we believe that all information in the registry must be widely accessible: Making this information confidential will be a barrier to the potential entry into our market of new energy retailers, which is contrary to the Guarantee’s objectives.” – Telstra

“How can the registry support customer transparency and have access to information, and access to registry accounts.

Access to information

Stakeholders put forward a range of views on the amount and type of information that should be made available.

“Alinta supports the majority of the ESB’s proposed design elements, including registry transactions remaining confidential, and suggests that allocation positions within the registry should also be treated as so.” – Alinta

“The publication of information from the registry needs to consider the need for transparency to deliver the most efficient outcomes and the need to ensure that commercially sensitive information is not exposed.

A significant amount of information on the NEM is already available publicly. For example, AEMO provides detailed data on dispatch by generating unit, as well as demand and wholesale spot prices. The AER publishes information on retail market shares in its annual State of the Energy Market report.

The information in the registry that will be publicly available will include:

- the emissions intensity of each generator to be used in the compliance year – published prior to the compliance year commencing
- the total volume of output (MWh) that has been allocated and each generator’s unallocated generation – updated regularly
- the residual emissions intensity – updated regularly, and
- the outcomes of each compliance year, including overall scheme outcomes and the emissions intensity of each market customer as set out in section 3.5.1.

The information in the registry that will not be published is individual allocations of generation and associated emissions and individual market customer loads. The ESB considers publishing this information would reveal sensitive information that would influence commercial negotiations. For example, it could increase the compliance costs of a market customer if the market knew the amount of low emissions generation to which it needed to obtain the rights.

Further consideration of the information to be published and the timing of publication will take place in developing the Rules.

Third party access to registry accounts

A number of stakeholders provided feedback that third parties or intermediaries should be able to hold an account in the registry. ACCIONA noted that “with the use of suitable access permissions, third party participation in the Registry and the type of information accessible, would be easily managed.” However, the ESB considers the inclusion of third parties would create a risk that they may have generator output allocated to them at the reporting deadline, but are not subject to compliance requirements. This would mean that there would be insufficient generation left in the registry to be allocated to market customers for compliance. To the extent that third parties held large allocations of emissions-intensive generation, targets would not be achieved in practice. Restricting access to the registry is the simplest way to mitigate this risk. As a result, third parties will not have access to the registry.

Information recorded in the registry

Each generator’s emissions intensity for a given compliance year will be recorded in the registry before the start of the compliance year.

Emissions data used to calculate the emissions intensity will primarily be sourced from NGER, for the financial year two years prior to the compliance year. This data is published by the Clean Energy Regulator by 28 February before the start of the compliance year.
Using data from the NGER scheme helps align emissions accounted for in the Guarantee with the electricity sector emissions that Australia reports in the National Greenhouse Gas Inventory. This can ensure that the emissions reductions achieved under the Guarantee align with the target for the sector set by the Australian Government. The National Greenhouse and Energy Reporting (Measurement) Determination 2008 provides methods, criteria and measurement standards for calculating emissions under the NGER scheme. It is updated periodically to reflect improvements in emissions estimation methods. By drawing on the data reported under the NGER scheme, the emissions under the Guarantee will reflect those methods for measuring emissions from electricity production.

A generator will be able to apply to the Clean Energy Regulator to receive an estimated emissions intensity that accounts for specific circumstances. These circumstances will include where the generator is new and does not have relevant historical emissions data and where the historical data is not reflective of a capital project that has a significant impact on the emissions intensity. The process for making such estimates and application requirements will be set out in a legislative instrument under the National Greenhouse and Energy Reporting Act 2007. The reporting or estimation of the emissions intensity of generators will also take account of when the NGER facility boundary includes emissions from major activities other than electricity production. For example, where a NGER facility includes a cogeneration plant, the emissions intensity for that generator would exclude emissions associated with the production of process heat.

Generation data used to calculate the emissions intensity will usually be for the financial year two years prior to the compliance year, to match the emissions data. For market generators it will be measured at the transmission node identifier (with generator imports netted against exports), and adjusted by the marginal loss factor that is current for the compliance year. For embedded generators it will be measured as the exports to the grid, adjusted by transmission and distribution loss factors.

From the start of the compliance period, pool generation and pool purchases data will be provided into the registry. This data is settled by AEMO in weekly batches, and each week’s data first becomes available four weeks in arrears. The pool purchases data are subject to 20 and 30 week revisions, but will be taken as final for the purpose of compliance as at end-September following the compliance year.

**Figure 1: Example of information recorded in the registry**

<table>
<thead>
<tr>
<th>Registry 2020-21</th>
<th>Generators</th>
<th>Generator X</th>
<th>Generator Y</th>
<th>Market customer emissions (tCO₂-e/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NGER emissions data</td>
<td>Generator emissions (tCO₂-e/MWh)</td>
<td>0.8</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Market customers</td>
<td>Generator dispatch</td>
<td>100,000</td>
<td>60,000</td>
<td></td>
</tr>
<tr>
<td>Market customer A</td>
<td>Generator dispatch</td>
<td>40,000</td>
<td>25,000</td>
<td>15,000</td>
</tr>
<tr>
<td>Market customer B</td>
<td>Generator dispatch</td>
<td>120,000</td>
<td>75,000</td>
<td>45,000</td>
</tr>
</tbody>
</table>

46 This example assumes the adjustments as discussed in section 3.3.2 are already accounted for.
Providing flexibility in how market customers meet the emissions reduction requirement will minimise instances of non-compliance and reduce the costs of the mechanism to market customers, and in turn electricity consumers.

3.4 Flexible compliance options

Providing flexibility in how market customers meet the emissions reduction requirement will minimise instances of non-compliance and reduce the costs of the mechanism to market customers, and in turn electricity consumers. This flexibility will allow market customers to manage variables such as unexpected generator outages and potential delays to the entry of new generators. The required emissions outcome for the NEM will still be achieved over the medium-term despite year to year fluctuations.

Flexible compliance options that will be in place for the emissions reduction requirement include that market customers will be allowed to carry forward a limited amount of a previous year’s over-achievement for use in a later compliance year, and will be allowed limited deferral of compliance to future compliance years.

3.4.1 Carrying forward over-achievement

The ability to carry forward over-achievement aims to incentivise investment when the market needs it and enable market customers to achieve compliance at a lower cost. While this outcome has merit, there is a real concern that the ability to carry forward over-achievement could lead to anti-competitive stockpiling. This practice could make it difficult for smaller retailers to access the allocations they require to comply with the emissions reduction requirement in future years. For this reason, a limit on the ability to carry forward is included.

“We support strong limits on the carry forward of over-achievement under the emissions reduction requirement, to ensure that there is sufficient opportunity for all participants to secure adequate contracts. This measure will act to safeguard competition.” – Energy Consumers Australia

In the draft detailed design consultation paper, the ESB had proposed a carry forward limit of 5 per cent of the first year’s electricity emissions intensity target per MWh of load plus a fixed amount of 60,000 tCO₂-e. While there were a range of views, the majority of stakeholder feedback through the consultation process was that this limit was too low to allow sufficient flexibility.

Several stakeholders proposed a higher limit. Origin did not support any carry forward limit, but suggested a higher limit of 20 to 30 per cent as a potential starting point. The Business Council of Australia recommended “increasing the initial limit to at least 10 per cent”. The Energy Users Association of Australia supported a limit of up to 15 per cent.

Meridian Energy Australia Pty Ltd and Powershop Australia Pty Ltd noted that they “support increasing the amount of carry-over but not so as to undermine investment signals in the market”. The Australian Industry Greenhouse Network (AIGN) argued that “allowing for increased flexibility at the outset and tightening the rules if necessary, is in AIGN’s view the better approach than the converse”.

The ESB has taken this feedback on board and increased the carry forward limit. Each year, a market customer will be able to elect to carry forward an amount (in tCO₂-e) of up to:

- 10 per cent of the electricity emissions intensity target for the first year of the emissions reduction requirement for each MWh of load, plus
- a fixed amount of 60,000 tCO₂-e.

No market customer will be allowed to carry forward an amount more than 100 per cent of the current year’s target as applied to its current year load.

48 For example, ACCIONA, AGL, Alinta, Clean Energy Council, Energy Users Association of Australia, ENGIE, and Hydro Tasmania.

29 ENERGY SECURITY BOARD • NATIONAL ENERGY GUARANTEE
The rationale for including a percentage limit with an absolute amount is to have a graduated limit applied based on the size of the market customer. This approach means that the largest market customers will face an effective carry forward limit of around 10 per cent of the first year’s target as applied to their load, whereas smaller market customers will have a higher effective limit, of up to 100 per cent.

To remain appropriate to market conditions, the limit will be able to be updated through rule-change processes if required in the future.

### Example of carrying forward over-achievement

Hypothetically, the electricity emissions intensity target for the first year of the emissions reduction requirement is set at 0.8 tCO₂-e/MWh.

**Market Customer A** has 10,000,000 MWh of load.
- They can carry forward a total amount of up to 860,000 tCO₂-e, calculated as:
  - \(800,000\) tCO₂-e \(= 10\% \times 0.8 \times 10,000,000\), plus
  - the fixed amount of \(60,000\) tCO₂-e
- This carry forward amount is equivalent to 10.75% of their load at 0.8 tCO₂-e/MWh.

**Market Customer B** has 50,000 MWh of load.
- They cannot carry forward the full amount of 64,000 tCO₂-e, calculated as:
  - \(4,000\) tCO₂-e \(= 10\% \times 0.8 \times 50,000\), plus
  - the fixed amount of \(60,000\) tCO₂-e
- This is because this full carry forward amount is equivalent to more than 100% of their load at 0.8 tCO₂-e/MWh \(= 64,000 / (0.8 \times 50,000) = 160\%\)
- Instead, they can only carry forward 40,000 tCO₂-e, equivalent to 100% of the electricity emissions intensity target multiplied by their load.

### 3.4.2 Deferring compliance

To provide adequate flexibility without undermining the objective of providing long-term policy confidence through delivery of the emissions reduction requirement, market customers will be able to defer 10 per cent of the electricity emissions intensity target per MWh of load. The limit will be cumulative over two years, with the market customer required to make good in the third year on the first year’s deferral amount.

The ability to defer 10 per cent over two years will provide sufficient lead time for market customers to make investments in generation to meet the electricity emissions intensity target, as needed. It will also assist market customers to manage annual variability in demand and variable renewable generation (including variable hydro production).

Beyond this limit, any additional increase in the market customer’s emissions intensity above the electricity emissions intensity target will mean the entity is non-compliant.

To remain appropriate to market conditions, the limit will be able to be updated through rule-change processes in the future.

### Accounting for target setting in the first year

Uncertainty will exist in electricity emissions intensity targets set by the Australian Government prior to the emissions reduction requirement commencing, regarding the expected change from business-as-usual reflected in the targets. The expected change relies on a number of forecasts, notably demand and the generation mix. Given the large pipeline of renewable projects expected to be commissioned around 2020, there is additional uncertainty on what would occur under business-as-usual. Over time there is less concern as the Guarantee will incentivise the appropriate mix of investment.

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54 This is because since all market customers have been able to comply, no anti-competitive hoarding forcing others into non-compliance has occurred.

55 This example assumes the adjustments as discussed in section 3.3.2 are already accounted for.
Accordingly, in the first year of the emissions reduction requirement, market customers will be able to defer their full compliance obligation. It will provide the sector time to adjust if the starting emissions intensity was higher than the first year’s electricity emissions intensity target.

Unlimited deferral in the first year of the scheme will mean market customers would not be considered in breach of the electricity emissions intensity target, nor face penalties or enforcement action in relation to their emissions intensity in that year (it would not, however, allow for unlimited carry forward of over-achievement in that year). Any deferral in the first year would need to be made good by the third year.

3.4.3 Use of offsets
The Australian Government has decided to allow market customers to use domestic Australian Carbon Credit Units (ACCUs) to help meet the emissions reduction requirement of the Guarantee. Use of ACCUs will be limited. This will be given effect through amendments to Australian Government legislation that will allow ACCUs to be surrendered in the Australian National Registry of Emissions Units (ANREU) for the purpose of counting towards the Guarantee and will set the limits on their use.

To give effect to the Australian Government’s decisions on offsets, the NEL will allow the use of offsets that are prescribed emissions units surrendered in the ANREU in accordance with the NER. Making provision in the NEL for the use of certain defined offsets will also ensure the Guarantee is robust to any future changes in the emissions reduction target.

The NEL will provide the ability for eligible offsets to count towards a market customer’s compliance calculations. Much of the detail on how this will be implemented under the Guarantee will be set out in the Rules on which the ESB will consult. In its consultation, the ESB will consider any further quantitative limits on the use of eligible offsets, such as the potential for setting individual market customer allowances, and any additional conditions that may apply.

3.5 Reporting and compliance
For the Guarantee to achieve its policy objectives, it is important to have a robust framework for monitoring and enforcing compliance with the emissions reduction requirement and its associated reporting requirements.

A market customer is ‘compliant’ with the emissions reduction requirement for a given compliance year when the emissions intensity of its allocated generation is at or below the electricity emissions intensity target for that year once all flexible compliance options have been considered. A market customer which exceeds the electricity emissions intensity target (once all flexible compliance options have been considered) is ‘non-compliant’.

Effective enforcement requires the enforcement agency to have resources to determine when an entity has not complied with its obligations, and to impose an appropriate penalty – one that is proportionate to the offence, acts as a deterrent, and provides greater certainty that the policy objectives are to be met.

3.5.1 Role of the AER
The AER will be responsible for monitoring and enforcing compliance with the emissions reduction requirement. In doing so, it will draw on a range of enforcement tools that already exist under the NEL. These are discussed in section 3.5.4. It will also use information provided by agencies such as AEMO and the Clean Energy Regulator.

The AER will be required to report annually on high-level outcomes for each compliance year, by 28 February following the compliance year. The information published will identify by name all market customers and their emissions intensities for the given compliance year. The information published will also include other relevant parameters, such as:
- the final emissions intensity of unallocated generation in the registry
- the extent of the use of flexible compliance options
- the extent of EITE exemptions provided, and
- the amount of load allocated to GreenPower.

This publication approach will help to promote and maintain a culture of compliance and provide transparency to electricity consumers.

3.5.2 The compliance period
The compliance period for the emissions reduction requirement will be on a financial year basis. The first compliance year proposed is 2020-21.

There will be a specified reporting and revision window after the end of each compliance year, with a deadline of mid-December. This will allow for relevant data (including audited embedded generation data) to be finalised by mid-November, and any allocation imbalances in the registry to be resolved in the following month. Following the mid-December deadline, the AER will commence assessing compliance for the year.
The proposed compliance framework for the emissions reduction requirement has been designed to minimise the reporting burden on market customers and generators.

3.5.3 Reporting and administrative requirements
The proposed compliance framework for the emissions reduction requirement has been designed to minimise the reporting burden on market customers and generators. Where possible, the reporting required to assess compliance will build on existing data sources (for which the existing frameworks for monitoring and enforcing reporting requirements will continue to apply). Where new information is required to assess compliance, such as emissions data for generation not currently captured in NGER, additional reporting requirements will be introduced. In doing so, the ESB will be cognisant to minimise duplication of existing reporting requirements and to draw on existing systems and associated compliance arrangements wherever possible.

The draft detailed design noted that the ESB was considering the merits of introducing:

- a general anti-avoidance regime in the NEL that relates to the Guarantee, intended to prohibit an entity which has a potential obligation under the Guarantee from restructuring or taking other action for the purpose of avoiding or minimising that liability, and
- a legal requirement that market customers and generators do not unreasonably withhold any allocations for anti-competitive purposes.

Stakeholder feedback received during the consultation process argued against the inclusion of anti-avoidance and unreasonably withholding provisions. Many stakeholders argued that these provisions would be challenging to enforce as they would depend on proving intent. For instance, Alinta argued in its submission that “the proposal of an anti-avoidance scheme in the NEM would introduce several highly subjective complexities in requiring regulators to analyse participants’ perceived intent.” Stakeholders also conveyed the view that competition issues of this nature sit outside the scope of the NEL.

Based on the feedback, the ESB has reconsidered the need for these provisions at this time and has decided not to include them in the final design of the emissions reduction requirement.

However, the AER will monitor the behaviour of the market over the initial years of the Guarantee’s implementation. The need for a general anti-avoidance provision or an unreasonably withholding provision may be reviewed at a later stage, if needed. The ESB will also explore whether targeted anti-avoidance provisions may be needed in respect of specific elements of the design of the Guarantee.

3.5.4 Enforcement tools for emissions reduction requirement
If, despite the flexible compliance options described in section 3.5, market customers fail to meet the emissions reduction requirement, the AER needs to be able to enforce compliance in a way that minimises costs for consumers. The AER already has access to a range of compliance tools and discretion in deciding whether to take enforcement action and the nature of that action. Each case is assessed on its merits. In determining an appropriate enforcement response, the AER considers all relevant factors and circumstances.

Guidance
The AER will publish guidance on the enforcement options within its power and the circumstances in which they are likely to be applied in the context of the Guarantee and the emissions reduction requirement. This will reflect the AER’s current practice of publishing guidance which is updated regularly.

Culture of compliance
The primary approach will be to build a culture of compliance. Minimising non-compliance is better than enforcement action after a breach has occurred. The AER will actively inform, educate and engage with the market to ensure participants understand their obligations and encourage compliance under the Guarantee. Annual reporting of registry outcomes will also encourage a culture of compliance.

Civil proceedings
The AER can initiate civil proceedings in the courts for alleged breaches of civil penalty provisions of the NEL:
• A court may order an injunction requiring an entity to do something or desist from doing something.
• A court may order that an entity pay a financial penalty (a ‘civil penalty’) as a result of breaching its obligations.

The existing definition of a civil penalty in the NEL will be amended to provide for more meaningful penalty levels to apply under the Guarantee.57 A civil penalty with a new upper limit of $100 million will apply in the circumstance of non-compliance by market customers with the emissions reduction requirement, as determined in each case by the court.

The civil penalty of up to $100 million provides a strong disincentive against non-compliance. In the event there are higher emissions reduction targets in the future, it provides a more meaningful penalty which should ensure that market participants respond effectively to the investment signals provided by the Guarantee.

The AER, at its discretion, may seek to undertake enforcement action for non-compliance with the Guarantee will be undertaken at the AER’s discretion. The AER’s guideline will indicate how it will take into account matters such as the extent of the breach and the size of the market customer. In the case of a civil penalty being issued, the court would exercise discretion when awarding a penalty. The new upper limit does not indicate that penalties of this magnitude would be issued for all non-compliance; instead, it gives the AER the power to seek a meaningful penalty if appropriate.

Additional enforcement options
The AER, at its discretion, may seek to undertake other enforcement options in place of, or in addition to, civil penalties:
• Administrative undertakings are a more informal and less intrusive enforcement option which the AER would use to resolve certain matters. The AER may be more likely to act administratively where the effect of an actual or potential contravention is limited, and an entity has taken (or agreed to take) appropriate steps to end the conduct and to remedy any harm done.
• Infringement notices give a recipient an option of paying a penalty in full (without there being an admission of breach) or electing to have the matter heard in court. The existing infringement penalty for a breach of a relevant civil penalty provision is $20,000.

57 It is likely this will need to occur irrespective of proposed changes to civil penalties currently being considered by the COAG Energy Council as part of its AER Powers and Civil Penalty Regime review.
• Court enforceable undertakings are written statements from an entity that it will take specified actions (for example, entering into contracts to resolve a breach). Compliance can be enforced by the courts. The AER may use enforceable undertakings to manage situations where market customers have clearly shown efforts to enter into contracts or arrangements but they have not delivered as expected. The AER may also use enforceable undertakings to require a market customer to make up in future years for a previous failure to meet its electricity emissions intensity target, to help ensure that the NEM, as a whole, does not fall short of the emissions reduction trajectory set by the Australian Government.

3.6 Other considerations

3.6.1 Interaction with the Large-scale Renewable Energy Target

The national Large-scale Renewable Energy Target (LRET) is designed to deliver 33,000 GWh of large-scale renewable generation per annum by 2020, the target does not increase beyond this. The Finkel Review found that “the Large-scale Renewable Energy Target scheme should remain unchanged to the end of its design life, but not be extended in its current form”.

The Guarantee brings together climate and energy policy for the first time; consequently, future investment in low emissions technology will be rewarded through the emissions reduction requirement of the Guarantee. However, the existence of the LRET and any participation in this scheme does not preclude this generation from also being included in the Guarantee and contributing to achieving the emissions reduction trajectory for the sector. Some stakeholders have argued that the LRET should be locked to new entrants once the target is met. This would artificially inflate the price of large-scale generation certificates and unnecessarily increase costs to customers.

The ESB supports the Finkel Review conclusion that no changes should be made to the LRET, which is legislated to continue through to 2030. Following the implementation of the Guarantee, the LRET should continue as legislated without closure to new entrants.

3.6.2 Interaction with voluntary accounting of scope 2 emissions

A number of end users employ the scope 2 emissions factors in the National Greenhouse and Energy Accounts (NGA) Factors document published by the Australian Government. They may use this to demonstrate how they are meeting sustainability goals or have purchased sufficient offsets to cover the emissions associated with their electricity use.

"With retailers required to publicly report their emissions intensities under the NEG it is unclear what the flow on effects will be to their customers who also report under NGERS e.g. would a property company who buys all its energy from retailer X be able to refer to retailer X’s emissions intensity for their scope 2 emissions instead of the NGA factors? In this context, does the proposed framework for the NEG make state-based NGA factors redundant? Further, is it intended that a retailer would be able to allocate its emissions intensity to customers based on contracts relating to specific generation assets? These are all issues that require clarification we strongly urge the ESB to conduct a broad review of carbon accounting practice across the economy and establish a consistent framework for use by all stakeholders.” – Property Council of Australia

Under existing arrangements, end users need to rely on state or NEM averages to measure emissions associated with the electricity use. The registry will provide an opportunity to identify a more granular view of the emissions intensity of electricity purchased from their retailer. One stakeholder identified opportunities to go further to allow end-users to take responsibility for Scope 2 emissions. “End use customers large and small that buy high GHG emissions electricity or buy from a high GHG emissions retailer should report and be socially accountable for high scope 2 GHG emissions” – Tim Kelly

The Australian Government is considering this issue.

60 Scope 2 emissions are the emissions released to the atmosphere from the indirect consumption of an energy commodity.
4 Reliability requirement
Reliability requirement

The reliability requirement builds on existing spot and financial market arrangements in the electricity market to facilitate investment in dispatchable capacity. It is designed to incentivise retailers, on behalf of their customers, to support the reliability of the power system through their contracting and investment in resources.

AEMO will forecast annually whether the reliability standard is likely to be met (or not) in each NEM region over a 10-year period. Where reliability gaps are identified, the market will have the opportunity to invest to resolve any gap in resources. However, if a material gap persists or emerges three years from the period in question, then AEMO will be able to apply to the AER to trigger the reliability obligation.

If the reliability obligation is triggered, retailers may be expected to demonstrate future compliance by entering into sufficient qualifying contracts for dispatchable capacity (including demand response) to cover their share of system peak demand at the time of the gap.

One year from the forecast reliability gap (T-1), if the AER confirms a material gap in resources remains, AEMO will use its safety-net Procure of Last Resort to close the remaining gap. At this point, liable entities must disclose their net contract position to the AER.

If actual system peak demand (at T) exceeds that which would be expected to occur one in every two years, then the AER will assess the compliance of liable entities.

The ESB has identified eight steps in the reliability requirement. These are captured in Figure 3 and detailed below.

Figure 3: Simplified timeline for various components of the reliability obligation

<table>
<thead>
<tr>
<th>Financial year</th>
<th>T-10 to 4</th>
<th>T-4 to T-3</th>
<th>T-3 to T-1</th>
<th>T-1 to T</th>
<th>T (gap)</th>
<th>T+</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>AEMO</strong></td>
<td>Material gap identified (AEMO EOG in August)</td>
<td>Build build</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>AER</strong></td>
<td>Independent trigger (communicate to liable entities)</td>
<td></td>
<td></td>
<td>Procurer of last resort triggered</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>RETAILER</strong></td>
<td>Manage obligation</td>
<td>Forecast 50 POE, Max Demand</td>
<td>Provide net contract position</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>LARGE CUSTOMER</strong></td>
<td>“Opt-in” (Retailer manages obligation by default)</td>
<td>Financial net exposure</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The ESB has identified eight steps in the reliability requirement. These are captured in Figure 3 and detailed below.
Since AEMO’s ESOO forecasts could form the basis of a regulatory obligation, they will be subject to a robust and transparent process along with an annual performance review.

4.1 Step 1: Forecasting the reliability requirement

Using the Electricity Statement of Opportunities (ESOO), AEMO will forecast whether the reliability standard is likely to be met (or not) in each NEM region over a 10-year outlook period. If the forecast is that the reliability standard will not be met, AEMO will identify the size of any ‘gap’ in supply/demand response.

To support liable entities to make informed decisions, additional descriptive information will be required to provide further context to AEMO’s forecasts including:

• an indication of the additional capacity required to ‘close’ the gap
• the pipeline of potential generation projects over the forecast period, along with progress of their development, and
• likely time of occurrence of the shortfall, such as month and time of day.

Since AEMO’s ESOO forecasts could form the basis of a regulatory obligation, they will be subject to a robust and transparent process along with an annual performance review.

To provide confidence to market participants in the quality of the ESOO forecast, AEMO will also be required to assess its forecasting process against AER best practice guidelines. The Rules will require that:

• AEMO will be required to consult on its forecasting process with stakeholders through a more formal consultation process (set out in published guidelines).
• AEMO will consult with stakeholders on defining performance metrics and consider back-casting as part of the performance monitoring. Forecast performance will be reported and published at least on an annual basis.
• AEMO will be required to publish and consult on a proposed improvement program, and then report on it as part of the next ESOO.

AEMO will continue to work with the Reliability Panel on the appropriateness of the current reliability standard in the face of an increasingly ‘peaky’ supply-demand balance. The intention of the Guarantee is to remain aligned to the reliability standard while ensuring there are adequate resources available to meet peak (as opposed to average) demand.

4.2 Step 2: Updating the reliability requirement

The ESOO publishes expected unserved energy (USE) forecasts to assess reliability in each region over a 10-year outlook. As expected USE is consistent with the framing of the reliability standard, this expected USE by region and year will continue to form the backbone of reliability assessment under the Guarantee.

AEMO will update the forecasts of the reliability requirement annually, or more frequently if there is a material change to the supply-demand outlook – such as when a generator announces retirement or there are significant changes in expected demand. This will build market confidence in the level of reliability risk which needs to be managed and help liable entities target investment effectively.

4.3 Step 3: Triggering the reliability obligation

Calculating the materiality of the ‘gap’

If a material reliability gap is identified in the forecasts, the market would be expected to react. This could take the form of investment in new capacity (for example, generation, transmission, storage or demand response) or an offer of additional existing capacity to the market.

If AEMO has identified a reliability gap in its ESOO forecast three years out from the period in which the gap is forecast, it will need to form a view on whether the gap is sufficiently ‘material’ to trigger the reliability obligation of the Guarantee. If it is, AEMO will be required to submit a request to the AER (the independent entity) to trigger the reliability obligation.

The basis for the assessment of materiality will be clearly defined and transparently communicated to support liable entities predict their potential obligations and close the gap as efficiently as possible.

To provide certainty to the market, the ESB has agreed to the following framework for assessment and communication:

• The Rules will set a materiality test for any reliability gap identified in the ESOO process. This will be an objective metric and two possible examples of such a metric are provided below.
• Once AEMO assesses a reliability gap as material, it would request the AER (as the independent entity) trigger the reliability obligation.
• At this point, the AER would have some discretion to decide not to trigger the reliability obligation even if the materiality metric is met objectively, having regard to the National Electricity Objective and matters set out in the Rules.
In making any decision to trigger the reliability obligation, the AER would follow a transparent and efficient process, set out in a Guideline, to give stakeholders confidence that the decision is justified.

Examples of possible materiality metrics

Example 1 – Expected USE exceeds the reliability standard
If the expected USE calculated by AEMO in its annual ESOO forecast for a given region and year exceeded the reliability standard, AEMO must request the AER trigger the reliability obligation.

Example 2 – Expected USE exceeds the reliability standard by a pre-determined amount
If the expected USE calculated by AEMO in its annual ESOO forecast exceeds the reliability standard in place at the time by X% (e.g. 0.0001), then AEMO must request the AER trigger the reliability obligation.

Similar to Example 1, there would be no discretion for AEMO in this approach. ‘X’ would be based on a probability of exceedance metric i.e. it would effectively define a confidence band around the reliability standard.

Whatever materiality test is adopted, the following principles will inform the development of Rules:

- The reliability gap will be calculated in a way that is consistent with the reliability standard set in the Rules. This is currently expressed as a weighted average estimate of USE.
- Estimates of the reliability gap in MW would be published as supplementary information, with the translation subject to the same consultation and scrutiny as AEMO’s other ESOO forecasts.

As part of the ESB’s stakeholder forum in July 2018, South Australia raised the question of whether to remove the T-3 trigger to simplify the reliability regime for the Guarantee. The ESB has undertaken some preliminary consultation with stakeholders on this suggestion. Stakeholder reactions have generally not been supportive and the ESB has been unable to reach a concrete view of the merits or otherwise of this suggestion in the time available. While there is potential that the removal of the trigger could further smooth contracting within the NEM, there is also a risk that removing the trigger results in contracting more capacity than what is ultimately required. Therefore, on balance, the ESB has decided to retain the trigger. The level and tenor of contracting will be considered when the operation and implementation of the scheme is assessed after three years with the potential to remove the trigger at that point if it would improve scheme operation.

The role of the AER as the independent entity approving the trigger
With the materiality test for the reliability gap to be set in the Rules, the role of the AER will be to provide confidence to stakeholders that the information and processes informing any decision to trigger the reliability obligation are robust. It will perform this function at both T-3 and T-1, a year ahead of a forecast gap (see Step 7 below).

In making any decision to trigger the reliability obligation, the AER would follow a transparent and efficient process, set out in a Guideline, to give stakeholders confidence that the decision is justified. The process would focus on the quality of AEMO’s forecasting process, including the validity of associated input assumptions.

The AER will develop additional technical capabilities to perform this new function under the Guarantee.

4.4 Step 4: Liable entities
If the reliability requirement is triggered, then all liable entities must assess their likely share of system peak demand and secure sufficient qualifying contracts, by the compliance date (T-1), to cover this.

As with the emissions reduction requirement, entities subject to the reliability requirement will be each entity registered by AEMO as a market customer under the Rules (mostly retailers, but also other parties that purchase electricity directly from the NEM).

Large customers (as defined in the Rules), who are not market customers, will be provided the flexibility to ‘opt in’ to manage their own reliability obligation. Large customers that manage their own reliability obligation may believe they can do so better, and at a lower cost, than a retailer but there will be no requirement to do so.

Submissions on the draft detailed design confirmed that most large customers preferred that liability under the reliability requirement rest with the retailer by default, and that large customers be provided the ability to opt-in.

“Large users are concerned that this [opt-out approach] would put them in a weaker negotiating position with retailers, exposing them to costs that would outweigh the benefits that the ESB hopes to achieve by encouraging longer and more predictable contracting.” – Australian Industry Group

This position has been accepted in the final design.

To further promote competition and avoid creating a disincentive for liable entities to take on commercial and industrial customers with energy demand at or below 30 MW, liable entities will be able to adjust their contract position between T-1 and T. This will allow liable entities to account for a specified material change in circumstances; such as where a retailer has taken on additional commercial and industrial customers.

However, the ability for liable entities to adjust contract positions between T-1 and T will not apply where a liable entity takes on a very large customer with demand above 30 MW (unless it is a new-entrant customer). This restriction is imposed to ensure the objectives of the reliability requirement are met.

The 30MW threshold includes an estimated 50 sites with total load of 4.1 TWh or more than 20 per cent of annual consumption in the NEM.

- A large customers’ peak demand will be determined by historical load performance, covering a period of at least 12 months to ensure the liability is based on an accurate reflection of their operational demand profile. The entity that has entered into the retail supply contract will be deemed liable.

- New entrants – for example, entities commencing operations during the compliance year – will be required to take steps to secure contracts or enter an agreement with a retailer to manage their obligation for load over the forecast gap period. Compliance with this requirement would be demonstrated by the new entrant through it reporting relevant actions to the AER.

If the reliability obligation is triggered, all liable entities will need to assess their likely share of system peak demand at the time of the reliability gap and secure sufficient qualifying contracts to cover this.

The existing contracts of large customers that choose to be a liable entity will be considered qualifying contracts subject to the load covered by the contracts in place. These contracts will need to have been in place on 10 August 2018 to be grandfathered and deemed to meet the reliability requirement (see Step 5).

4.5 Step 5: Qualifying contracts

If the reliability obligation is triggered, liable entities will be required to enter into sufficient qualifying contracts to cover their share of system peak demand at the time of the reliability gap to meet possible future compliance.

Qualification framework

There is a range of existing contract types, such as caps and swaps, which expose the sellers of those contracts to very high prices if generation or demand response is not available when the system needs it. Generally speaking, these types of contracts are only offered if they are underpinned by dispatchable capacity or demand response; that is, capacity that is available to be dispatched when the system needs it.

Consistent with this, any wholesale contract with a direct link to the electricity market which a liable entity can use to reduce exposure to high wholesale spot prices will qualify.

If a material gap persists one year from the forecast reliability gap (T-1), liable entities will be required to submit their net contract position to the AER – and in doing so, to ensure that the net position submitted has been appropriately adjusted for the ‘firmness’ of contracts used for compliance (each contract approximated by a ‘firmness factor’ that is supported by an independent audit report). The level of firmness assigned to each contract will need to reflect the unique characteristics of each contract such as strike price, the likelihood of cover over the period of the gap, and any other relevant terms.

The calculations and the appropriateness of the methodology used to determine this factor will need to be supported by an independent auditor’s report submitted to the AER. The liable entity’s net position will need to be signed off by an appropriately authorised officer of the company. Consistent with the arrangements in the National Energy Retail Law, the AER will also have the power to audit this information, or require an audit, and the liable entity must pay the costs of this.

The ESB considers that this framework provides the right balance between flexibility and assurance that firm capacity will be available when and where it is needed. The majority of stakeholders consulted supported this position.

For example:

“Infigen supports the proposed approach to qualifying contracts – this will ensure that firm capacity is available, but provide flexibility as to how firmness is procured, including the use of interregional contracts.” – Infigen

Market Liquidity Obligation

To help manage significant stakeholder concerns about the liquidity and transparency of contract markets, large, vertically-integrated retailers will be covered by a ‘Market Liquidity Obligation’ when the reliability obligation is triggered.

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63 This estimate includes all sites larger than 30 MW and captures approximately 17 TWh load from market customers. Excluding market customers, load captured by the 30 MW threshold represents approximately 13 per cent of annual NEM consumption.
64 Also known as a contract’s ‘delta’.
• This will require at least two vertically-integrated retailers per region [with separate consideration required for Tasmania] to make contracts available, for the period of the gap, on an appropriate trading platform.\(^66\)

• Liability for the obligation will be determined based on a size threshold and will need to involve more than one vertically-integrated retailer in each region.

• Obligated participants will be required to post bids and offers, with a maximum spread, for standardised products in the relevant region that would cover the period of the gap.

• Additional safeguards will be required to ensure that obligated participants can reasonably meet their requirements.

The Market Liquidity Obligation will be an important measure in addressing market power in supply constrained conditions.

"ERM Power believes that this MLO would be effective in countering the risk of economic withholding as well as helping small retailers access contracts during times of tight supply-demand balance. " – ERM Power\(^67\)

The detailed design of the Market Liquidity Obligation will be further developed in consultation with industry and will be set out in the Rules.

This process will address specific issues raised by stakeholders in feedback on the draft detailed design, including the definition of obligated participants by region, the trading platform used to meet the obligation in each region, eligible products, the maximum bid-offer spread for eligible products, interaction with other market making schemes, and what additional safeguards are necessary to ensure obligated participants can meet their requirements without taking on excessive risk.

The ESB notes that the ACCC has, in its Retail Electricity Pricing Inquiry, recommended an ongoing market making obligation for South Australia. Should this be implemented, it will be important that the two obligations are interoperable.

With the Market Liquidity Obligation in place, the ESB does not consider that the costs of establishing a trade repository\(^68\) are warranted to satisfy the objectives of the Guarantee. However, the ESB notes that the ACCC has recommended that all over-the-counter (OTC) transactions be reported in a de-identified format to promote greater transparency in OTC contract markets. This recommendation will be considered by governments in due course.

Voluntary ‘book-build’

If the reliability obligation is triggered, AEMO may invite interested parties to lodge an expression of interest to participate in a voluntary book-build mechanism.

The book-build will provide an opportunity for liable entities to secure contracts which are underpinned by new physical resources. It will further assist liable entities – in particular, small retailers or large customers who choose to manage their own reliability obligation – to lock in qualifying contracts.

• Contracts delivered through the book-build will qualify for compliance under the reliability obligation.

• The book-build will be conducted by inviting sellers to make offers to sell new contracts for the duration of the gap and buyers to make offers to buy new contracts. AEMO will match buyers and sellers in a way that delivers the maximum closure of the gap. All risks will be borne by participants.

• If the reliability obligation has been triggered, AEMO will be able to run the book-build three years out from a forecast gap, and if the gap persists, AEMO will have the option to re-run the book-build again two years out.

Some stakeholders responding to the draft detailed design suggested that the objectives of the book-build process can be achieved through the Market Liquidity Obligation. The ESB’s final position is to retain the book-build. This will provide additional assurance that any material reliability gap is addressed and that the Guarantee does not undermine market competition, while providing market participants with a low-cost means of securing firm contracts in tight supply demand conditions.

A review of the role of the book-build will be undertaken after three years of operation.

Demand response contracts

The development of demand response contracts that qualify under the reliability obligation will be central to ensuring the reliability requirement of the Guarantee is met at least-cost. Contracts will qualify provided they meet the same criteria as other financial instruments; that is, a direct link to the electricity market which a liable entity can use to manage exposure to high spot prices. The demand response will have to be ‘in-market’, meaning it is not eligible to be contracted by AEMO through the Procurer of Last Resort, and allocated to a liable entity and a supply region.

\(^66\) Hydro Tasmania has a dominant market share of generation capacity in Tasmania (approximately 88 percent, with interconnector capacity making up approximately 12 percent). As such, alternate approaches will need to be considered. The ESB will consult on this issue as part of the development of the Rules.


\(^68\) Trade repositories are entities that centrally collect records of OTC derivatives in a number of sectors.
In addition to providing AEMO visibility of demand response in its forecasting processes and to support compliance, demand response contracts will need to be registered with AEMO via its Demand Side Participation Portal. To avoid under- or over-counting, activated demand response will be added back to a liable entity’s share of peak demand.

4.6 Step 6: Procurer of Last Resort

The Procurer of Last Resort is the ‘safety net’ for the reliability obligation.

One year from the forecast reliability gap, AEMO will again review its forecast. If the reliability standard is now forecast to be met there is no further action. However, if the reliability obligation has been triggered and a reliability gap persists one year out, the AER will again review AEMO’s forecasts and, if a material gap remains, activate the requirement for retailers to provide their net contract position to the AER. Concurrently, AEMO will commence procurement of resources through the RERT framework to address the remaining gap.

Any resources procured via the RERT framework will be for supply ‘outside of the market’ to avoid distorting the operation of the electricity market, consistent with the RERT rules.69

If AEMO and/or a relevant state government feels that the specific circumstances in a particular jurisdiction dictate that prudent action is required to ensure the ongoing reliability of the electricity system, then a rule change could be expedited to enable AEMO to commence its Procurer of Last Resort function earlier than one year before the forecast reliability gap. However, it is not the intention of the Guarantee for AEMO to become the default procurer of capacity for the NEM.

4.7 Step 7: Compliance

If the reliability obligation is triggered and a reliability gap persists in one or more NEM regions one year out, liable entities in the region/s will be required to submit their net contract position to the AER to demonstrate they have sufficient enduring qualifying contracts over the gap period.

Following the compliance period, if peak demand exceeds the one in two-year forecast threshold, the AER will assess the contract positions submitted by liable entities and confirm if the level of contract coverage was adequate to meet their obligation.

- The AER will use data for the relevant trading intervals in a region in which demand exceeded the one in two-year forecast to determine each liable entity’s share of demand in that interval.
- It will then compare liable entities’ net contract position with their share of actual demand in that interval [determined based on metering data provided by AEMO], scaled back to the one in two-year system peak forecast consistent with the ‘safe harbour’ provision that contracts should only be required to meet the one in two-year system peak forecast. The calculation of each liable entity’s actual demand will be determined by the AER based on metering data provided by AEMO.

Where liable entities are under-contracted in one or more trading intervals, the AER will calculate the shortfall across the relevant compliance period. This shortfall will be used to determine and assign penalties for non-compliance.

The details of the compliance framework will be further developed in consultation with stakeholders and will provide guidance on the types of information that will need to be reported to the AER and the form in which that information is to be reported.

4.8 Step 8: Penalties

Penalties will be assigned to liable entities that have insufficient qualifying contracts for their load.

A two-part approach to compliance and assignment of penalties will be undertaken:

- The first aspect of the penalty framework for the reliability obligation will allocate costs to liable entities that have failed to meet their contractual obligations. A liable entity found to be non-compliant will be charged a proportionate cost based on its contribution to the Procurer of Last Resort costs. A non-compliant entity’s costs for this first stage will be capped at $100 million.
- In the second aspect, the AER will retain its ability to apply its usual suite of enforcement options in addition to the assignment of Procurer of Last Resort costs in stage one. These enforcement options would likely only be used for more significant or repeated failures to comply with the reliability obligation. They comprise administrative undertakings, enforceable undertakings and civil proceedings, including the issue of financial penalties.

The definition of civil penalty in the NEL will be amended to provide a meaningful upper limit on the financial penalties which can be assigned for non-compliance under the reliability obligation. Similar to rebidding civil penalty provisions, the ESB considers up to $1 million would be an appropriate upper limit on first offences, with up to $10 million the upper limit on repeat offences.

69 The AEMC is currently considering a rule change proposal to enhance the RERT framework, including the lead time of procurement, duration of contracts, the merits of introducing standardised products and options to strengthen governance and transparency.
5 Governance
The Guarantee mechanism will be implemented through amendments to the NEL and the Rules.

5.1 Implementation through NEM governance arrangements

Embedding the Guarantee mechanism into the existing NEL and Rules will allow the mechanism to be fully integrated within the broader energy governance framework. This will maximise consistency between the Guarantee’s reliability and emissions reduction requirements and the existing regulatory requirements of the NEM, reducing complexity and compliance costs for market participants.

Amendments to the NEL, after being agreed by the Energy Council in accordance with the AEMA, will be implemented by the South Australian Parliament and automatically applied in each of the other participating jurisdictions of the NEM (other than the Northern Territory).

There will be a period of public consultation on the draft NEL amendments, which is anticipated to occur from around mid-August to around mid-September. It is expected that the draft legislation will then be finalised for introduction to the South Australian Parliament by the end of 2018.

The NEL will set out:
- who is liable under the emissions reduction and reliability requirements
- the key aspects of those requirements, and
- the compliance and penalty framework.

It will also include a new emissions objective to guide rule-making in relation to Rule changes relevant to the emissions reduction requirement and additional functions and powers for the AEMC, AEMO and the AER to support implementation of the Guarantee.
The necessary changes to the Rules to implement the Guarantee will be made by the South Australian Energy Minister in mid-2019, following a period of consultation with stakeholders. Detailed aspects of the Guarantee will be included in the Rules.

After the initial package of changes to the Rules are made, the AEMC will be the rule-maker in response to rule change proposals and in accordance with its current functions under the NEL. It will be able to assess and accept rule change requests from any entity relating to those aspects of the Guarantee contained in the Rules, following the well-established AEMC rule-making processes set out in the NEL.

This will give participants clarity in relation to how and when revisions to the mechanisms will occur, recognising that the design of the Guarantee is already flexible to changing market dynamics.

The key steps and consideration involved in implementing the Guarantee are outlined in Figure 5.

**Figure 5: Timeline for Guarantee agreement and implementation**

<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 August 2018</td>
<td>COAG Energy Council meeting</td>
</tr>
<tr>
<td>Late September 2018</td>
<td>COAG EC approves final legislation</td>
</tr>
<tr>
<td>April 2019</td>
<td>Package of Rules agreed by COAG EC</td>
</tr>
<tr>
<td>Mid August 2018</td>
<td>Exposure draft legislation to COAG EC</td>
</tr>
<tr>
<td>November-December 2018</td>
<td>Legislation considered by SA Parliament</td>
</tr>
</tbody>
</table>

**5.2 Review of operation of aspects of the Guarantee mechanism**

Certain aspects of the operation of the Guarantee will be reviewed after three years. These include:

- The need for additional specific provisions around unreasonable withholding of low emissions allocations.
- The need for general anti-avoidance provisions applying to emissions and reliability obligations under the Guarantee.
- The operation of the three-year trigger mechanism to consider the level and tenor of contracting.
- The role of the book-build mechanism.

**5.3 Relevant Commonwealth legislation**

As outlined above, the Guarantee will be implemented primarily through amendments to the NEL after agreement by the COAG Energy Council.

Commonwealth legislation will be required in relation to:

- **Setting the emissions targets:** The NEL will refer to the Commonwealth targets, which will form the emissions intensity target under the Guarantee.
- **EITE exemptions:** When calculating liable load under the Guarantee, the NEL and Rules will exempt load consumed by EITE activities, as calculated under Commonwealth legislation through a certificate mechanism administered by the Clean Energy Regulator.
- **The use of offsets:** Offsets will be stored and surrendered in the Australian National Registry of Emissions Units, which is governed by Commonwealth legislation, and administered by the Clean Energy Regulator. The NEL and Rules will incorporate the definitions of allowable units and limits on surrender for compliance purposes under the Guarantee.
- **Emissions reporting:** Commonwealth legislation will determine the reporting and calculation arrangements for the emissions intensity of generators (administered by the Clean Energy Regulator), which will be incorporated into the Guarantee’s registry.
- **Related information sharing and gathering powers.**
6 Modelling
6.1 Modelling framework

The updated Guarantee modelling has been conducted using ACIL Allen’s proprietary market simulation model – PowerMark – to project outcomes for the NEM over the period from 2018-19 to 2029-30. At its core, PowerMark is a simulator that emulates the settlements mechanism of the NEM. PowerMark uses a linear program to settle the market, as does AEMO’s NEM Dispatch Engine in its real-time settlement process. PowerMark is part of an integrated suite of models including models of the market for Renewable Energy Certificates and the wholesale gas market.

Wholesale spot prices in the NEM are determined every half hour by an auction process. These scenarios were modelled on an hourly basis, replicating the dispatch process for 8,760 spot prices for each year. Demand is included as an exogenous assumption and presented to the market against which generator portfolios compete for dispatch.

A distinctive feature of PowerMark is its iteration of generator bidding. PowerMark constructs an authentic set of initial offer curves for each unit of generating plant prior to matching demand and determining dispatch through the market clearing rules. PowerMark encompasses re-bids to allow each major generation portfolio in turn to seek to improve its position – normally to maximise (uncontracted) net revenue, given the specified demand and supply balance for the hourly period in question. The projected wholesale spot price of electricity is a direct output from PowerMark’s simulation of the bidding activity of generators.

Spot price outcomes are a function of the market structure as modelled including scarcity pricing and use of portfolio market power at times of tight supply-demand balance, constrained by the current NEM Market Price Cap, Market Floor Price, Cumulative Price Threshold and the Administered Price Cap. Aside from already committed new generation projects which are known to have a very high likelihood of being built, new generation capacity is introduced on a commercial basis in response to energy spot price signals. In the long-term, such market simulation modelling should show price outcomes reflecting the cost of new entrant generation for the various parts of the price duration curve.

All dollar figures in this chapter are expressed in real 2018 terms unless otherwise noted.
6.2 Assumptions and approach

In order to conduct quantitative modelling, a number of input assumptions must be made. Many of these assumptions are technical in nature, and include forecasts of future demand levels, fuel prices and technology costs. The technical assumptions used in this modelling incorporate the best available and up-to-date information on the outlook for the NEM, and have been sourced from a range of publicly available sources — often from published estimates from AEMO. They have been supplemented by ACIL Allen’s own in-house assumptions for other key inputs.

Sensitivity testing has also been completed to test the effects of changes in key assumptions — for example the difference in results using different estimates of the future cost of various technologies are described towards the end of this chapter. Assumptions relating to the expected operation of the Guarantee and its effects on the investment and policy environment incorporated into the ACIL Allen modelling were made by the ESB. Many of these are common to all scenarios and are outlined in Table 1.

The purpose of this analysis was to gain insight into the expected effects of the Guarantee on the NEM. It does not seek to examine in detail other policies that particular NEM jurisdictions may continue to pursue. It differs in purpose to the modelling conducted to support AEMO’s recently released Integrated System Plan, and reflecting this employs some different modelling frameworks and approaches.

It is important to note that the modelling results presented are not a prediction of the future. Rather, their value lies in providing a comparison between the projected effects of different policy scenarios as a result of an internally consistent framework. Some of the assumptions made necessarily relate to long-term forecasts which are subject to a degree of uncertainty, and changes in these factors over time will have an effect on price and generation outcomes. Further, even very detailed modelling frameworks cannot capture all the real-world detail that may affect generation and price outcomes in the NEM.

Table 1: Key assumptions

<table>
<thead>
<tr>
<th>Demand</th>
<th>Estimates from the AEMO Electricity Forecasting Insights March 2018 update ‘neutral’ scenario, adjusted to reflect modelled generation coverage.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Behind-the-meter factors:</td>
<td></td>
</tr>
<tr>
<td>Solar PV</td>
<td>Based on AEMO Electricity Forecasting Insights neutral estimates</td>
</tr>
<tr>
<td>Electric vehicles</td>
<td>Based on AEMO Electricity Forecasting Insights neutral estimates</td>
</tr>
<tr>
<td>Battery storage</td>
<td>Based on AEMO Integrated System Plan neutral estimates</td>
</tr>
<tr>
<td>Demand response</td>
<td>‘No policy’: based on the AEMO Integrated System Plan weak Demand Side Participation assumptions</td>
</tr>
<tr>
<td></td>
<td>‘Guarantee’: based on the AEMO Integrated System Plan strong Demand Side Participation assumptions</td>
</tr>
<tr>
<td>Fuel costs</td>
<td>ACIL Allen estimates.</td>
</tr>
<tr>
<td>(coal and gas)</td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>The marginal price of coal for electricity generation is assessed in consideration of the specific circumstances for each generator taking into account:</td>
</tr>
<tr>
<td></td>
<td>– Suitability of coal for export and the assumed international thermal coal price</td>
</tr>
<tr>
<td></td>
<td>– Location of power station in relation to the mine and export terminals</td>
</tr>
<tr>
<td></td>
<td>– Mining costs</td>
</tr>
<tr>
<td></td>
<td>– Existing contractual arrangements</td>
</tr>
</tbody>
</table>


72 For example reflecting its strategic planning purpose and longer time horizon of interest, the analysis underpinning the Integrated System Plan examines system resource cost outcomes rather than modelling price outcomes or the way that generator profitability may affect investment decisions.
### Fuel costs (coal and gas) (continued)

Coal prices are expected to moderate somewhat from their currently elevated levels. International thermal coal prices are assumed to converge to US$60 per tonne in the long-term from around US$120 per tonne currently.73

**Gas**
- Gas market is modelled in ACIL Allen’s GasMark Australia model
- Real gas prices for power generation are projected to moderate slightly from their current range of around $7-11/GJ in 2017-18 over the period to 2020-21 before increasing over the 2020s to a range of between $9 and $14 per GJ by 2029-30.

### Retirements

Announced retirements are reflected in the modelling. Other plant are assumed to require life-extension refurbishment when they reach the end of their expected technical life, and retire unless life-extension refurbishments are projected to be economic. Plant will also retire when they are no longer projected to profitably operate.

### Committed build

A list of large scale renewable projects considered committed to be built in the NEM over the next three years is at Table 3. In addition, the Commonwealth’s Snowy 2.0 expansion, committed projects under the plan to replace the Liddell Power station in NSW announced by its owners, and stage one of the VRET and QRET schemes are considered committed.

### Snowy 2.0

Snowy Hydro 2.0 assumed to become operational in 2023-24 with 2,000 MW of additional pumped hydro storage (battery) generating capacity, along with a consequential increase to VIC-NSW transfer capability to enable its effective operation.

### State-based renewable policies

Stage one of the announced state renewable energy targets in Victoria (VRET) and Queensland (QRET) are included. That is, 400 MW of capacity in Queensland and 650 MW of capacity in Victoria.

Further stages of these schemes are not included.

### Financing costs: Weighted average cost of capital for new entrants

- **Pre-tax WACC of 6.3% in 2018 rising to 8.9% by 2030 as interest rates normalise from current lows (assumes constant 60/40 debt-to-equity financing ratio)**

### Uncertainty premium

- No policy case assumes an additional uncertainty premium of 3 percentage points (post-tax) which is removed under the Guarantee

### Emissions abatement target

- **‘No policy’: No Commonwealth target**
- **‘Guarantee’: NEM is constrained to deliver a carbon budget consistent with reducing its emissions to 26% below NEM 2005 levels by 2030. Total allowable emissions are around 1,320 MtCO₂-e over 2020-21 to 2029-30. The start point for the carbon budget was set at the expected ‘no policy’ level of emissions in 2020-21 of around 135 MtCO₂-e. The end point was set 26% below the 2005 level of NEM emissions as estimated in the National Greenhouse Gas Inventory of 176 MtCO₂-e.**

### Contract coverage of existing generation capacity

Increases by 5% under the Guarantee

### Macroeconomic assumptions

- Exchange rate of 0.75 AUD/USD; inflation rate of 2.5%.

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73 This projected decline in coal prices is broadly consistent, for example, with the trends in recent forecasts published by the Australian Department of Industry, Innovation and Science in their June 2018 Resources and Energy Quarterly and in the World Bank’s April 2018 Commodity Price forecasts.
6.3 Scenario 1 ‘No policy’

To test the relative performance of the Guarantee we first need to define the reference case, the ‘no policy’ case, against which the Guarantee policy case is compared.

This case is intended to represent a plausible future for the electricity market in the absence of the Guarantee or any other additional national climate change and reliability policy being introduced. It is characterised by an environment of policy uncertainty that may well persist if agreement within and among Australian governments on energy policy is not reached.

The effects of this continued environment of heightened uncertainty are captured through a judgment that only those new entrant projects currently committed will be built in the short-term, and in a higher cost of financing for new entrant projects. In this environment of uncertainty, the demand response market is expected to develop towards the lower end of current expectations – and the available volumes of demand response and the prices at which they are available are assumed to be consistent with the ‘weak’ DSP assumptions used in the AEMO Integrated System Plan.74

Chart 10 provides a high-level overview of the results from the ‘no policy’ scenario. It should be noted that the results shown are only for scheduled and semi-scheduled generation (a subset of operational demand), which are generators that AEMO can issue dispatch instructions to adjust their output over specified timeframe.75

Consumption met by grid-supplied electricity is forecast to remain relatively flat over the projection period based on the AEMO demand forecasts adopted. Business demand is forecast to remain flat, while net residential demand is projected to decline as growth in population and appliance usage is offset by increased generation from rooftop solar PV and by energy efficiency initiatives.76

In 2017-18 wholesale prices are at elevated levels of around $85/MWh (on a time-weighted basis) in part due to the recent closure of the Hazelwood power station in Victoria and increases in coal and gas costs in recent years.

The ‘no policy’ modelling projects that wholesale prices in the NEM will decrease to around $50/MWh by 2020-21. This is primarily due to an expected increase in NEM capacity of around 7,800 MW over 2018-19 to 2020-21 owing to the addition or completion of committed utility scale wind, solar and battery storage projects and stage 1 of the VRET and QRET schemes. Assumed declines in coal costs also contribute to the lower price outcomes in this period. Current investment momentum is understood to reflect current elevated prices, incentives under the national RET and State renewable schemes, strong corporate demand for renewable power purchase agreements and some optimism associated with the prospect of a national agreement on an integrated climate change and reliability policy for the electricity sector.

While the closure (as announced) of the Liddell coal-fired power plant in NSW in 2022-23 puts some upward pressure on prices, the replacement capacity announced by the ownership of Liddell together with the addition of around 2,000 MW of capacity with the completion of the Commonwealth Snowy 2.0 pumped hydro project in 2023-24 is projected to put further downward pressure on prices, broadly offsetting the price effects of Liddell retiring and extending a period of lower prices. Wholesale prices are then projected to rise slightly over the latter half of the decade as the demand-supply balance tightens and real gas prices – an input to gas-fired generation – rise. Some QLD black coal generation is projected to withdraw in line with key contracting and technical milestones around 2029-3077 – which causes a further slight increase in the modelled wholesale price trajectory at this time.

Under the ‘no policy’ scenario projected wholesale prices are 31 per cent lower relative to 2017-18, on average, over the period from 2018-19 to 2029-30.

Under the ‘no policy’ scenario the generation mix over the period is projected to change to reflect the committed new renewable build. The modelling suggests that the renewable share of NEM generation (sent out) will increase from 17 per cent in 2017-18 to 34 per cent by 2029-30.

Coal powered generation is expected to continue to account for over 60 per cent of all generation in 2029-30.

The modelling suggests that annual emissions in the NEM will decrease from around 151 MtCO2-e in 2017-18 to around 133 MtCO2-e by 2029-30. This is driven by rapid reductions to 2020-21 as a result of the committed new renewable build, before flattening out and slightly rising towards the end of the period as forecast demand increases, and dipping in 2029-30. The NEM is projected to fall short of the emissions reduction target of 26 per cent below 2005 levels.

75 AEMO’s operational demand definition also includes output from significant non-scheduled generation, most of which comprises wind farm output.
77 The modelling suggests that under this scenario, it will not be profitable for some Queensland black coal capacity to undergo necessary refurbishments in 2029-30, a time which coincides with the expiration of a major power purchase agreement.
The total value of wholesale energy purchased in the NEM over the period 2020-21 to 2029-30 under the ‘no policy’ scenario is projected to be around $118 billion. The average annual value of wholesale energy purchased in the NEM over the period 2020-21 to 2029-30 under the ‘no policy’ scenario is projected to be around $12 billion. This is an almost $5 billion average annual reduction on the estimated total value of wholesale electricity in the NEM in 2017-18.

Chart 10: Projected NEM outcomes under ‘No policy’ scenario

<table>
<thead>
<tr>
<th>Scenario 1: No Policy</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Residential retail bill savings relative to 2017-18</strong></td>
</tr>
<tr>
<td>Real $2018 / annum</td>
</tr>
<tr>
<td>Wholesale prices $/MWh</td>
</tr>
<tr>
<td>CO2-e emissions Mt</td>
</tr>
<tr>
<td>Generation mix (sent out)</td>
</tr>
<tr>
<td>Generation capacity</td>
</tr>
</tbody>
</table>

a) Real network costs held constant b) NEM wholesale prices are projected time-weighted regional price series weighted by NEM region projected load. c) Shares of scheduled and semi-scheduled generation as well as rooftop PV.
6.4 Scenario 2 ‘Guarantee’

The Guarantee is expected to provide additional policy confidence and stability. These effects of the Guarantee are modelled by removing the additional financing costs associated with policy uncertainty in the ‘no policy’ case; and by assuming that the current observed momentum in commitment to new-build investment as the Guarantee is developed slows but does not suddenly cease as assumed in the ‘no policy’ case.

Agreement to implement the Guarantee will underpin the continued confidence in the market and is expected to result in the further commitment of 1,000 MW of renewable generation relative to the no policy scenario – this approach is consistent with the ESB’s engagement with stakeholders that has suggested recent renewable investment trends have been in part supported by the likelihood of an agreement to implement the Guarantee.

The Guarantee is also expected to increase the volume of long-term contracting in the NEM as all retailers and large market customers will be required to have a reliable level of firm contracts in place at key times when the reliability obligation is triggered. Even in instances where the reliability obligation is not triggered, the ESB expects the Guarantee to incentivise market participants to engage in more long-term contracting up to an appropriate and sustainable level. This is reflected in the modelling by assuming the average contracted load of existing generators increases by 5 per cent. This is consistent with the approach taken by Frontier Economics in the previous modelling exercise conducted by the ESB. This leads to more competitive bidding in the spot market as generators offer more capacity at short-run marginal cost to cover their contracted capacity. Generators with high levels of long-term contracts in place are heavily financially incentivised to be able to generate in contracted time-periods.

Contracting in the NEM

Generation portfolios enter into electricity derivative contracts to hedge a portion of their wholesale revenues in order to reduce earnings risk and avoid insolvency.

In entering into these contracts, generators are indifferent to spot price movements across the volume of these contracts except where the spot price falls below their marginal cost. Therefore, a short-term optimal strategy for generators is to offer all capacity that is contracted at marginal cost.

To the extent they can, generators will seek to optimise net revenue outcomes for their uncontracted capacity. This is often referred to as ‘strategic bidding’ and is typically employed during periods of tight supply and demand. The level of contract cover for generators within the market is therefore a key short-term setting in market modelling exercises. It is often set by reference to recent observed bidding behaviour in the market and has historically equated to around 80 to 85 per cent of dispatch. However, in recent years the increase in intermittent renewable capacity and the closure of thermal plant has left less swap contract cover available to the market.

Increasing the amount of generator capacity under contract will tend to lead to a more competitive market in the short term with generators offering more capacity at marginal cost and resulting spot price outcomes will be lower as a result. However, this setting would be expected to have little impact on annual spot price outcomes modelled in the longer-term as annual prices converge to new entrant costs.

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78 The modelling framework assumes that new generation plant will be built when the expected net present value of the project is positive, based on the expected future revenues of the project from the spot market or other sources of revenue such as the RET or low-emissions or reliability premia associated with the Guarantee. On this basis, the modelling framework would not have built all of the approximately 7,800 MW of new-entrant build committed and expected to connect to the NEM in the coming three years. As such, consideration must be given to the drivers of this new build and assumptions made whether the existing momentum should be expected to continue. While only a small portion of the already committed pipeline, the ESB considers that at least an additional 1,000 MW of generation would have already committed were it not for the current policy uncertainty, and will quickly reach financial close once the Guarantee is agreed. This estimate is consistent with ESB’s market intelligence, and supported by stakeholder submissions to the policy development process, see for example the Powershop and EnergyAustralia comments published on pages 8 and 9 of this report.

79 The level and tenor of contracting will be considered when the operation and implementation of the scheme is assessed in due course with the potential to remove the reliability obligation trigger at that point if it would improve scheme operation.

Annual average residential retail electricity bills are projected to be around $550 lower, on average, over the 2020-21 to 2029-30 period than in 2017-18. The modelling suggests that around $150 of that saving is additional savings due to the implementation of the Guarantee.

The incentives and structures created by the Guarantee are also expected to accelerate the development of the demand-side response market. This has been modelled by changing the assumptions associated with the availability and pricing of demand response from the AEMO Integrated System Plan ‘weak’ assumptions (under the ‘no policy’ scenario) to the ‘strong’ assumptions. The Guarantee is designed to ensure that reliability is maintained and emissions abatement targets are met. Reflecting this, the model is constrained to ensure that a minimum reserve level of capacity is maintained in every region in every time period. In any instance that a shortfall is identified, changes in firm contract premia are applied which are sufficient to incentivise a supply or demand-side response to close the gap. If required these costs are added to retail bills. The energy-only market delivers sufficient capacity to ensure the reliability standard is expected to be met in the ‘Guarantee’ scenario.

Chart 11 provides a high-level overview of the results from the Guarantee scenario. The modelling suggests that the Guarantee will place substantial additional downward pressure on prices. NEM-average wholesale prices (time-weighted) are projected to be over 20 per cent lower, on average, between 2020-21 and 2029-30 under the Guarantee than without it.

Annual average residential retail electricity bills are projected to be around $550 lower, on average, over the 2020-21 to 2029-30 period than in 2017-18. The modelling suggests that around $150 of that saving is additional savings due to the implementation of the Guarantee. Projected retail prices are lower for all customer types under the Guarantee.

The modelling suggests that under the Guarantee the renewable share of NEM generation (sent out) will increase from 17 per cent in 2017-18 to 36 per cent by 2029-30. Coal powered generation is expected to continue to account for over 60 per cent of all generation in 2029-30. There are no additional coal power station closures that occur under the Guarantee that do not occur under the ‘no policy’ scenario.

Under the Guarantee, annual emissions in the NEM are projected to decrease from 151 MtCO₂-e in 2017-18 to 130 MtCO₂-e by 2029-30. Total emissions in the NEM under the Guarantee are projected to be around 1,305 MtCO₂-e over the period from 2020-21 to 2029-30. This is around 15 MtCO₂-e under the 1,320 MtCO₂-e carbon budget implied by the target of 26 per cent below 2005 levels by 2030. Scenarios which include the potential use of international or domestic carbon offsets were not modelled. However, the use of offsets would be an option only exercised if it lowered compliance costs for market participants. To the extent that offsets are used for compliance, NEM emissions would tend to be higher than if they had not been used, as the certified reduction in emissions associated with the offset would occur outside the NEM.

The total value of wholesale energy purchased in the NEM over the period 2020-21 to 2029-30 under the ‘Guarantee’ scenario is projected to be around $91 billion. This is a reduction of around $27 billion relative to the outcomes projected under the ‘no policy’ scenario. The average annual value of wholesale energy purchased in the NEM over the period 2020-21 to 2029-30 under the ‘Guarantee’ scenario is projected to be around $9 billion.

82 Only estimated bill savings expected to occur as a result of reductions in the price of wholesale electricity or reductions in the cost of green scheme subsidies are included in this figure. For conservatism and simplicity, savings that may result from reductions in network pricing relative to 2017-18 were not included.
Chart 11: Projected NEM outcomes under “Guarantee” scenario

Scenario 2: Guarantee
Residential retail bill savings relative to 2017-18

Wholesale prices

CO2-e emissions

Generation mix (sent out)

Generation capacity

a) Real network costs held constant. Blue shading depicts savings additional to ‘no policy’ b) NEM wholesale prices are projected time-weighted regional price series weighted by NEM region projected load. c) The carbon budget (cumulative allowable emissions) is the area under the red line. d) Shares of scheduled and semi-scheduled generation as well as rooftop PV.
6.5 Technology cost assumptions

Current and future capital cost profiles for each generation technology are key input assumptions in this type of modeling exercise. These numbers can determine the types of generation that the model builds and how much of them are built as prices and the demand-supply balance in the system change.

In order to test the sensitivity of the central ‘no policy’ and Guarantee scenarios to technology costs, variants of each scenario were run using more aggressive declines in capital costs for certain technologies which were identified across a survey of available estimates (see Table 2). Both scenario variants were identical to the central cases, implying that the results do not hinge on the technology cost assumptions in this particular example. As such the results are not included here.

Table 2: Key technology cost assumptions

<table>
<thead>
<tr>
<th>Real 2018 $/kW, installed</th>
<th>No policy/Guarantee</th>
<th>Low tech costs scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2018</td>
<td>2030</td>
</tr>
<tr>
<td>Wind</td>
<td>2,053</td>
<td>1,650</td>
</tr>
<tr>
<td>Solar SAT</td>
<td>1,469</td>
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</tr>
<tr>
<td>Solar thermal</td>
<td>5,531</td>
<td>4,400</td>
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<tr>
<td>OCGT</td>
<td>819</td>
<td>806</td>
</tr>
<tr>
<td>CCGT</td>
<td>1,230</td>
<td>1,224</td>
</tr>
<tr>
<td>Black coal (super-critical)</td>
<td>3,072</td>
<td>3,043</td>
</tr>
<tr>
<td>Pumped hydro</td>
<td>1,429</td>
<td>1,364</td>
</tr>
<tr>
<td>Large scale battery storage (4 hrs)</td>
<td>2,031</td>
<td>959</td>
</tr>
</tbody>
</table>

6.6 Projected jurisdictional outcomes

Chart 12: Projected time-weighted annual wholesale regional reference prices without the Guarantee
Chart 13: Panel of projected jurisdictional annual time-weighted wholesale prices

<table>
<thead>
<tr>
<th>New South Wales</th>
<th>Queensland</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="chart13a.png" alt="Graph" /></td>
<td><img src="chart13b.png" alt="Graph" /></td>
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<th>South Australia</th>
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<tbody>
<tr>
<td><img src="chart13c.png" alt="Graph" /></td>
<td><img src="chart13d.png" alt="Graph" /></td>
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<tr>
<th>Victoria</th>
<th>NEM</th>
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</thead>
<tbody>
<tr>
<td><img src="chart13e.png" alt="Graph" /></td>
<td><img src="chart13f.png" alt="Graph" /></td>
</tr>
</tbody>
</table>
Chart 14: Panel of projected jurisdictional energy mix (sent out) – No policy scenario
Chart 15: Panel of projected jurisdictional energy mix (sent out) – Guarantee scenario

**NSW**

<table>
<thead>
<tr>
<th>Year</th>
<th>Black Coal</th>
<th>Gas</th>
<th>Hydro</th>
<th>Solar</th>
<th>Wind</th>
<th>Rooftop PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>17-18</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>19-20</td>
<td>100%</td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>24-25</td>
<td>100%</td>
<td></td>
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<tr>
<td>29-30</td>
<td>100%</td>
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**QLD**

<table>
<thead>
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<th>Year</th>
<th>Black Coal</th>
<th>Gas</th>
<th>Hydro</th>
<th>Solar</th>
<th>Wind</th>
<th>Rooftop PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>17-18</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>19-20</td>
<td>100%</td>
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<tr>
<td>24-25</td>
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<td>29-30</td>
<td>100%</td>
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**SA**

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<thead>
<tr>
<th>Year</th>
<th>Gas</th>
<th>Solar</th>
<th>Wind</th>
<th>Hydro</th>
<th>Rooftop PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>17-18</td>
<td></td>
<td></td>
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<td>40%</td>
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<tr>
<td>19-20</td>
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<td>20%</td>
<td>40%</td>
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<td>29-30</td>
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<td></td>
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<td>40%</td>
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**TAS**

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<thead>
<tr>
<th>Year</th>
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<th>Solar</th>
<th>Wind</th>
<th>Hydro</th>
<th>Rooftop PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>17-18</td>
<td></td>
<td></td>
<td>20%</td>
<td>40%</td>
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<td>19-20</td>
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<td>29-30</td>
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<td>20%</td>
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</tbody>
</table>

**VIC**

<table>
<thead>
<tr>
<th>Year</th>
<th>Brown Coal</th>
<th>Gas</th>
<th>Solar</th>
<th>Hydro</th>
<th>Wind</th>
<th>Rooftop PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>17-18</td>
<td></td>
<td>20%</td>
<td>40%</td>
<td>20%</td>
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<td>19-20</td>
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<td>20%</td>
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<td>24-25</td>
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<td>20%</td>
<td>40%</td>
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<tr>
<td>29-30</td>
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<td>20%</td>
<td>40%</td>
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**NEM**

<table>
<thead>
<tr>
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<th>Brown Coal</th>
<th>Gas</th>
<th>Solar</th>
<th>Hydro</th>
<th>Wind</th>
<th>Rooftop PV</th>
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<tbody>
<tr>
<td>17-18</td>
<td></td>
<td></td>
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<td>40%</td>
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<td>40%</td>
<td>20%</td>
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</tbody>
</table>

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This chart was updated in the online version of the report on 3 August 2018 to correct a minor error in the projected jurisdictional generation mix (sent out) under the Guarantee. This correction affects the chart graphic only, and there are no changes to the analysis, figures or text in the report. An addendum reflecting this change was published on 3 August 2018.
6.7 Operation of the Guarantee under different circumstances

The Guarantee is expected to improve outcomes in the NEM under a variety of circumstances. It is possible that higher emissions reduction targets (that is, a larger percentage reduction in emissions) may be set in the future by the Australian Government. This would require a change to Australian Government legislation. However, the Guarantee framework will automatically accommodate new targets.

Higher targets create greater demand for lower emissions intensity allocations under the emissions reduction requirement, providing investment signals for existing and new low emissions intensity generators, but will not change the fundamental operation of the Guarantee. The strong disincentives against non-compliance, including a penalty of up to $100 million, allow the design to accommodate higher targets and ensure that market participants respond effectively to the investment signals provided by the Guarantee.

In the absence of a policy such as the Guarantee that takes into account both emissions and reliability, higher targets could mean an increase in the share of variable renewable generation to a point where reliability becomes an issue. However, under the Guarantee, the reliability requirement ensures that firm capacity (including demand response) is contracted by liable entities. Coupled with wholesale market prices, this will incentivise investment in dispatchable resources so that more stringent targets do not impact on reliability.

The Guarantee is further expected to improve outcomes in the NEM in difficult circumstances such as those associated with significant unexpected generator outages or exits. Increased contracting – which incentivises generators to defend their sold contract positions or face significant financial liabilities – may lessen the chance of unexpected exit and increase a generator’s incentive to keep the plant well-maintained and quickly take action to respond to any unplanned outages. More fundamentally, the reliability obligation of the Guarantee will reinforce the value of firm contracts in times and regions when supply of these contracts is at risk of becoming scarce. The historical case study in section 2.4 above illustrates some of the potential benefits of additional contracting.
### 6.8 List of committed projects to 2020-21

<table>
<thead>
<tr>
<th>Region</th>
<th>Station</th>
<th>Technology</th>
<th>Average capacity in 2020-21</th>
<th>Increase in capacity relative to 2017-18</th>
<th>Capacity online part way through 2017-18</th>
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Note: totals may not add exactly due to rounding.
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### A Abbreviations and defined terms

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<th>Abbreviation</th>
<th>Definition</th>
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<td>ACCU</td>
<td>Australian Carbon Credit Unit</td>
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<td>Australian Energy Market Agreement</td>
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<td>Emissions-intensive trade-exposed</td>
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