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EXECUTIVE SUMMARY

The National Energy Guarantee (Guarantee) is an opportunity to resolve some of the most vexing policy issues challenging the National Electricity Market today. But the Guarantee cannot solve all of these policy issues alone. As recommended in the Finkel review, Energy Security Board members are also simultaneously exploring a range of other complementary measures including strategic reserve/s, demand response and day ahead markets to ensure we have the operational flexibility we need in the rapidly changing electricity market.

Fifteen years of climate policy instability has complicated long-term investment decisions and required responses for system reliability and security have not been forthcoming. This has left our energy system vulnerable to escalating prices while being both less reliable and secure.

A well-designed Guarantee will bring together climate and energy policy for the first time in Australia to ensure 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 is critical to bringing down electricity prices.

The Guarantee will provide a clear investment signal so the cleanest, cheapest and most reliable generation gets built in the right place at the right time. It can also signal opportunities for demand response which may help reduce the need for costly new generation infrastructure.

The emissions and reliability components of the Guarantee will require retailers to support a range of different generation technologies through their contracting. Increased contracting in deeper and more liquid contract markets is expected to reduce the volatility and high prices we’ve seen in our wholesale National Electricity Market over the last year further improving the affordability of electricity.

Over the last decade policy makers have attempted to design the perfect emissions trading scheme and every attempt has failed. The emissions requirement under the Guarantee is simply that— a requirement. It is a requirement on retailers to ensure that the energy they are purchasing is in line with the emissions reduction targets set for the electricity sector.

The Australian Government has provided a section for this consultation paper on the matters within its area of responsibility. This section sets out some possible options for how electricity sector emissions targets might be set, reviewed and adjusted along with the treatment of our emissions intensive, trade exposed sectors and the possible use of domestic or international offsets.

The Energy Security Board has built on this and considered some of the design options for the emissions component including how to calculate a retailer’s load and emissions, the provision of flexible compliance options and the necessary frameworks for reporting and compliance.

The reliability and emission components complement one another and are designed to ensure the market has a fair opportunity to deliver adequate reliability. That is, that we have sufficient investment in dispatchable megawatts or demand response to meet peak demand. This will require retailers to enter contracts to deliver their share of the required MWs in a region at a point in time for a given duration.

The reliability requirement should build on existing spot and financial market arrangements to facilitate investment in dispatchable capacity. The Energy Security Board has identified eight key steps to a reliable energy supply with a number of design options at each step:

1. **Forecasting the reliability gap**: AEMO forecasts whether the reliability standard is likely to be met (or not) in any NEM region over a forecast period.
2. **Updating the reliability gap**: AEMO updates the forecasts of any reliability gap over time, as the market changes e.g. to reflect a notification of retirement of a particular generator.
3. **Triggering the requirement**: If a reliability gap has been identified, the market would be expected to react and start to invest in new capacity or offer additional existing capacity to the market to close the gap. When a gap persists, there will be a point in time in advance of any forecast reliability gap at which the reliability requirement is ‘triggered’ and retailers are then expected to respond.
4. **Qualifying instruments**: Retailers will be incentivised to make investments or enter into contracts that underpin new investment that can alleviate the identified gap. Participants will need to know what instruments will ‘qualify’ for meeting the reliability requirement. Retailers will be required to demonstrate that they have entered sufficient eligible contracts to cover their share of the peak demand requirement at the time of the reliability gap.
5. **Allocating the requirement:** If there is an identified gap and the obligation has been triggered, there will be a defined process for filling or allocating the gap to retailers.

6. **Compliance:** At the compliance date, the AER will need to assess whether retailers have met their reliability requirement.

7. **Procurer of last resort:** If retailers do not meet the requirement by the compliance date, AEMO will need to procure resources to fill any remaining gap.

8. **Penalties:** Penalties will need to be assigned to retailers that have fallen short of their reliability requirement.

Perhaps the most important section of this consultation paper is the section on Governance. Stable and effective implementation of the Guarantee will provide certainty for market participants about its operation and allow for long term investment decisions to be made in the electricity sector. While the Guarantee could be implemented in various ways, the Energy Security Board’s preferred option is for implementation through existing governance arrangements for the NEM. The majority of the Guarantee could be implemented through amendments to the Australian Energy Market Agreement (AEMA), the National Electricity Law (NEL) and the National Electricity Rules (Rules). The established rule change process will enable refinement of the Guarantee across time without the need for disruptive large-scale reviews.

We proposed a policy mechanism that has the potential to significantly contribute to a more reliable and affordable electricity system and that is in step with our international emissions obligations. COAG Energy Council has given us the space to undertake further work and consultation and we seek to work with you on developing the layers of detail necessary to implement this policy approach.

This initial consultation paper seeks your feedback on the high-level design options for the Guarantee. The consultation process will be short and targeted to enable us to offer a preferred high-level design to the COAG Energy Council at their April 2018 meeting. With COAG Energy Council agreement in April, we will commence the detailed design of the Guarantee through intensive consultation with stakeholders over several months before putting a preferred detailed design to COAG Energy Council later this year. This will not be your final chance to input to this policy process.

We value your thoughts and your input is essential if we are to deliver meaningful change in a sufficiently short space of time.

ENERGY SECURITY BOARD
1 Introduction and next steps

On 24 November 2017, the COAG Energy Council agreed that the Energy Security Board should provide further advice on a National Energy Guarantee (Guarantee). This is to be provided in April 2018, after broad consultation. The initial advice on the Guarantee broadly and conceptually set out changes needed to the National Electricity Market (NEM) and its legislative framework such that:

- the reliability of the system is maintained
- the emissions reductions required to meet Australia’s international commitments are achieved
- the above objectives are met at the lowest overall costs.

This initial consultation paper has been prepared by the Energy Security Board to facilitate public consultation on the high-level design of the proposed Guarantee and to seek stakeholder submissions. The content of this document does not represent the views of the COAG Energy Council.

Subject to COAG Energy Council in-principal agreement to proceed with the detailed design of the Guarantee, further consultation will be undertaken from May to July 2018.

1.1 Background to the consultation paper

The Energy Security Board is responsible for the implementation of the reform blueprint produced by Australia’s Chief Scientist, Dr Alan Finkel AO. The Energy Security Board also provides whole of system oversight for energy security and reliability to drive better outcomes for consumers.

The Guarantee, as described above, is about addressing reliability and emissions reduction. However, the Guarantee will not directly address the provision of a range of services including system strength, inertia, ramping and flexibility, which are also required for a secure and reliable system. The Energy Security Board considers that additional market design changes will be necessary as set out in the Finkel Review. The Finkel Review recommended further consideration of a number of key market design changes including assessing the need for a Strategic Reserve, the suitability of a ‘day-ahead’ market and the development of a mechanism that facilitates demand response in the wholesale energy market. Each of these potential market design changes are integral to the Energy Security Board’s consideration of the Guarantee. How the Energy Security Board and market bodies are addressing these matters is set out in appendix B.

1.2 Consultation process and submissions

The Energy Security Board intends to consult broadly in developing the Guarantee. Stakeholders have a range of opportunities to be involved, as detailed below.

Public forum and webinar
The Energy Security Board will hold a public forum and webinar on this consultation paper in Sydney on 26 February 2018. Information about how to register for this public forum and webinar is available on the COAG Energy Council’s website.
Submissions to the consultation paper

The Energy Security Board invites comments from interested parties in response to this initial consultation paper by 8 March 2018. All submissions will be published on the COAG Energy Council’s website, subject to any claims of confidentiality. All submissions should be sent to info@esb.org.au.

The Energy Security Board notes that chapter 4 discusses material received from the Commonwealth Government on elements of the emissions obligation that are matters for Commonwealth Government decision. These include how the sectoral emissions reduction target will be set, the eligibility of offsets and how exemptions for emissions-intensive trade-exposed (EITE) activities will be treated. Stakeholder feedback received on these matters will be will addressed by the Commonwealth Government.

Next steps

Following receipt of stakeholder submissions on the consultation paper, the Energy Security Board will incorporate stakeholder feedback into the paper establishing the proposed high-level approach to implementing the Guarantee. The timeline for progression of the Guarantee is set out below.

<table>
<thead>
<tr>
<th>Date</th>
<th>Action</th>
<th>Status</th>
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<tbody>
<tr>
<td>15 February 2018</td>
<td>Energy Security Board releases Guarantee consultation paper</td>
<td>The Energy Security Board consults on high-level design of the Guarantee for stakeholder consideration, drawing on Commonwealth input on the emissions target, the use of offsets and EITE exemptions.</td>
</tr>
<tr>
<td>26 February 2018</td>
<td>Public forum and webinar on consultation paper</td>
<td>Energy Security Board presentations on design elements and Commonwealth Government presentations on the emissions target, the use of offsets and EITE exemptions.</td>
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<tr>
<td>8 March 2018</td>
<td>Written submissions due on consultation paper</td>
<td></td>
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<tr>
<td>Early April</td>
<td>Energy Security Board provides draft design paper for COAG Energy Council consideration</td>
<td>The Energy Security Board incorporates stakeholder feedback into paper establishing proposed approach to implementing the Guarantee</td>
</tr>
<tr>
<td>Late April</td>
<td>COAG Energy Council considers policy approach and provides direction on the progression of detailed work on the Guarantee</td>
<td></td>
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<tr>
<td>Late April</td>
<td>High-level design paper published</td>
<td></td>
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<tr>
<td>May - July</td>
<td>Energy Security Board working papers / workshops on various detailed elements of Guarantee design</td>
<td>Stakeholder input requested on detailed design elements in order to develop legislative and rule change requirements</td>
</tr>
<tr>
<td>Second half of 2018</td>
<td>Energy Security Board releases final design document for consultation Commonwealth releases proposed changes relating to Commonwealth</td>
<td>Stakeholder input requested on final design proposal</td>
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<td>emissions design elements for consultation</td>
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<tr>
<td>Second half of 2018</td>
<td>Energy Security Board provides final design of the Guarantee for COAG</td>
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<td>Energy Council decision on final design of the Guarantee</td>
<td>Legislation and rule drafting begins</td>
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1.3 **Structure of this consultation paper**

This consultation paper is structured as follows:

- Chapter 2 provides some context for the Guarantee.
- Chapter 3 discusses the Energy Security Board’s proposed design for the emissions requirement.
- Chapter 4 discusses material that the Energy Security Board has received from the Commonwealth Government, on the elements of the emissions requirement that are matters for Commonwealth Government decision. These include how the national emissions target will be set, how external offsets may be used and how EITE exemptions will be treated. The Commonwealth Government is seeking feedback on these policy areas discussed below through the Energy Security Board’s consultation.
- Chapter 5 discusses the Energy Security Board’s proposed design for the reliability requirement, including a number of potential design options.
- Chapter 6 outlines the Energy Security Board’s preferred governance option for the Guarantee.
2  Context for the Guarantee

2.1  Overview of the Guarantee

The Guarantee will require retailers to contract with, or directly invest in, generation, storage or demand response so that:

- there is a minimum amount of dispatchable energy available to meet consumer and system needs (reliability requirement); and
- the average emissions level of the electricity they sell to consumers supports Australia’s international emission reduction commitments, as set by the Commonwealth Government (emissions requirement).

The Guarantee is a way to encourage new investment in clean and low emissions technologies while allowing the electricity system to continue to operate reliably. To deliver this transition, the Guarantee requires retailers to contract with or invest in generators or demand response to meet specified minimum levels. Retailers must also keep their emissions per megawatt hour (MWh) below an agreed level.

The integration of energy and climate policy is expected to reduce the risk premium on new investments improving the affordability of electricity. Increased contracting in a more liquid contract market is also expected to reduce the level of wholesale electricity spot prices and their volatility.

‘Retailers’ is used throughout this paper and refers to the market participants that will be subject to the Guarantee.

2.2  Reliability vs security

Currently, in the NEM, reliability means having an adequate amount of capacity (both generation and demand response) to meet consumer needs, as well as having an adequate amount of network capacity (including interconnectors) to transport this energy to where consumers want it. This involves longer-term considerations such as having the right amount of investment, as well as shorter-term considerations such as making appropriate operational decisions, to make sure an adequate supply is available at a particular point in time to meet demand. To deliver a reliable supply, the level of supply needs to include a buffer, known as reserves, so that supply is greater than expected demand. This allows demand and supply to balance, even in the face of unexpected changes. Reliability is different to security, as explained in Box 2.1.

Box 2.1: Reliability vs security in the NEM

System security: A secure system is one that is able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security events are mostly caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency.

Reliability: A reliable system is one with enough energy (generation and demand side participation) and network capacity to supply consumers – this implies that there should be enough energy to meet demand, with a buffer known as reserves.

2.3  A transforming energy system

Australia’s energy system is evolving - driven by changing consumer choices and rapidly evolving technology. Meanwhile, various policy settings – including environmental policies – are having a profound influence on consumption, investment and operational decisions being made in energy markets. In particular, there are three key emerging trends that are affecting Australia’s energy system.

First: the growing potential role of the demand-side, including the potential for loads to interact more directly in the wholesale market. Historically, a ‘reliable’ power system invariably meant back-up generation, the availability of additional generating units to ramp up if others failed. However, the emergence of new technologies and ensuing regulatory developments has meant that reliability is no longer the virtually exclusive domain of ‘supply-side’ solutions. Rather, the demand-side – including residential customers – now has a potentially important role to play in delivering a reliable power system at the lowest possible cost. Indeed, consumers are becoming better-equipped than ever to manage and control their energy use and contribute to reliability and this will only improve in the future. The demand-side is a key factor in driving the transformation of the energy sector.
Second: the changing mix of generation being the increase in intermittent technologies, such as solar, storage and wind generation, and the reduction in dispatchable coal-fired generation. Historically, most of the installed generation capacity has been “dispatchable” (that is, 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, with the mix of generation in the NEM changing rapidly there is a steadily declining percentage of dispatchable generation. This creates challenges in operating the system in a secure and reliable manner because of the increased variability and uncertainty.

Operationally, this change in generation mix is challenging for system security, as well as reliability, because different technologies have different characteristics. The rules of physics dictate various technical features that are needed for system security - like frequency control, inertia, and voltage parameters. Coal, gas and hydro generation have spinning generators, motors and other devices that are synchronised to the frequency of the power system. This synchronous generation can support system security almost as a by-product. The ability of non-synchronous forms of generation such as wind, battery storage and solar photovoltaic powered generators to provide these features easily is still developing. As the proportion of non-synchronous generation rises, the variables that influence security of the power system is becoming more diverse.

Third: the continuing uncertainty over key policies, such as future emissions reduction policies. Continued uncertainty around how any emissions reduction mechanism could be integrated with the energy market has not been positive for investment in new generation. Investors may not respond to higher price signals due to uncertainty surrounding their future. The Guarantee addresses these issues by combining reliability outcomes and emissions targets to guide investment in and operation of the lowest cost resources (demand-side or supply-side). It is designed to integrate energy and emissions policy and signal how much electricity the market needs and when it is needed, while also ensuring Australia’s emissions targets are met.

In this context, AEMO has suggested to the Energy Security Board that in order to ensure a reliable and secure system in the future, a range of essential services including system strength, inertia, ramping and flexibility. Several potential sources for these services have been posited - generation, demand response, batteries and a more diverse power system through more interconnectors. Thus, in addition to the Guarantee, new tools and mechanisms will be needed to address emerging security issues. How the Energy Security Board and market bodies are addressing these matters is set out in Appendix B.

### 2.4 Australia’s emissions reduction policy objectives

Australia has committed to reducing its emissions by 26-28 per cent on 2005 levels by 2030. The wholesale electricity generation sector accounts for around one-third of Australia’s emissions.

Achieving Australia’s emissions reduction goals at lowest cost to consumers must be done by encouraging new investment in a balanced mix of technologies that address both reliability and emissions reductions. Prices have been rising partly as a result of the same changes that are causing the system security and reliability concerns.

The principal national mechanism to reduce emissions in the wholesale electricity generation sector currently is the Renewable Energy Target (RET). The RET is a policy mechanism designed to encourage investment in large-scale renewable energy technologies. The RET policy sits outside the energy market framework and the design of the RET was not focused on working with the risk allocation and incentive mechanisms built into the NEM that align the financial incentives of market participants with the physical needs of the power system.

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2.5 Contracting in the NEM

As the Guarantee imposes an obligation on retailers to contract with or invest in low emission and dispatchable generation or demand response, it is important to understand how contracting takes place in the NEM.

In interconnected power systems, the amount of electricity being produced from multiple supply sources needs to continuously match the amount of electricity being consumed. Because of the need to co-ordinate supply and demand in real time, the NEM has a formal spot market, operated by AEMO. This primarily operates to co-ordinate the operation of the power system, but also provides revenue to participants which assists with providing a return for capacity investments.

In addition, there is a hedge contracts market, in which derivatives (of the spot market) are traded, assisting market participants with their risk management. The contract market also helps new investment to be financed, influencing decisions as to whether and when to undertake maintenance and retire and smoothing retailers’ wholesale electricity purchase costs.

An individual generator's revenues, and a retailer's costs, are determined by their net exposure to these two markets. All energy traded through the NEM must be settled through the spot market. Generators are paid the spot price for the electricity they produce and retailers pay the spot price for the electricity their customers consume. The variability of demand and supply conditions results in fluctuations in a spot price on a 30 minute basis. Prices in the spot market can currently range from the Market Floor Price of -$1,000/MWh to the Market Price Cap (MPC) of $14,200/MWh.

These fluctuations in prices encourages both buyers and sellers to enter into contracts that convert volatile spot revenues and costs into a more certain cashflow. Prices in the contract market are derived from outcomes in the spot market, with contracts typically settled by reference to the spot market price for a particular region. This financial derivatives contract market has been an integral part of the operation of the NEM since its inception. Hedging against these risks can significantly reduce market participants' (and ultimately consumers') exposure to high price events.

The market for contracts serves the following four purposes:

1. It provides a mechanism for retailers and generators to manage their exposure to spot prices, by allowing participants to trade uncertain and variable spot market prices for fixed prices going forward.

2. On a short-term operational timescale (e.g. hourly), generators who have sold contracts are incentivised to be available when needed (i.e. when spot prices are high), in order to defend their position and so earn revenues in the spot market to fund payouts on their contract positions. This incentive to ‘turn up’ is heightened during high price/tight demand-supply periods, which is precisely when the system most values the generator’s output.

3. It lowers the cost of financing investment in generation capacity, which lowers the cost of achieving and maintaining system reliability. Contracts provide generators a steadier stream of revenue

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2 Generators and registered loads are also paid for ancillary services provided. AEMO co-optimises the need for energy and ancillary services and compensates generators accordingly.

3 Although note that the AEMC has recently made a final determination to move to five minute settlement from mid 2021.

4 The market floor price forms part of the “reliability settings” in the NEM (along with the market price cap, cumulative price threshold and administered price cap). In particular, the market floor price prevents market instability, by imposing a negative limit on the total potential volatility of market prices in any half hour trading interval.

5 This arrangement is sometimes referred to as a “gross pool”.

6 The Australian Energy Market Commission (AEMC) recently made a determination to move to five minute settlement from 2021. The AEMC’s analysis suggests that five minute settlement will still allow for hedging and risk management, and that generators will have strong incentives to continue selling the same, or similar, contracts to what they currently offer.
compared to taking spot price exposure. This reduces the risks to parties providing funding to
generators, such as debt and equity holders, that the value of their investments may not be
recouped. This lowers the overall cost of capital required to finance the project and lowers the cost
of the new generation capacity.

4. It underwrites retailers’ fixed-price offers to end-consumers, such as households and small
businesses. Like generators, retailers use the contract market to mitigate their exposure to the spot
market. Contracts provide retailers with a consistent price for electricity, which in turn allows them
to offer longer-term contracts, with stable prices, to their retail customers.

As noted in the ESB’s November 2017 advice to the Commonwealth, an increased amount of contracting by
existing generators results in more competitive bidding in the spot market as generators bid lower to
increase their chances of being dispatched in order to defend their contracted position. This is likely to result
in lower spot prices.

Hedge contracts (e.g. swaps or caps) create a link between the needs of the system for capacity and the
financial rewards that accrue to generators from being available and dispatched and the losses or penalties
they incur if they are not. The various types of hedge contracts and the payments and receipts flowing from
them have this effect because they are linked to the NEM spot prices reflecting the demand-supply balance
at a particular point in time.

It is this link to the physical production of electricity underpinning these financial arrangements that caused
the Australian Treasury to exempt over-the-counter (OTC) electricity derivatives from new reporting
requirements following the global financial crisis.

This link between the physical and the financial spot market outcomes is not as strong under any scheme
that provides “certificate” revenue to generators based on a type of technology or its emission levels (i.e. the
RET). While certificate revenue may support, sn any generation capacity that is not financed through a
mechanism linked to either spot prices or directly to a customer’s load and retail contract, does not have a
strong financial incentive to be available when the physical system needs it the most.

New generation financed under the RET adds to the physical capacity of the system, but does not directly
result in a corresponding increase of hedge contracts. This is because typically, renewable generation is
intermittent and so cannot easily enter into these contracts without undertaking other investments e.g.
having a hybrid site with both wind & solar, or installing a battery.

Policy mechanisms that incentivise investment in electricity generation capacity without incentivising the
ongoing supply of hedge contracts risk adversely affecting wholesale and retail market outcomes and
system reliability. They will inadvertently lessen the emerging competition from innovative new retail energy
businesses, and place upward pressure on consumer prices. Conversely, where a policy mechanism is
effectively integrated and aligned with the design of the NEM, it is likely to lead to a higher degree of
investment certainty in the energy market and more availability of contracts. This will reduce pressure on the
wholesale electricity market, reduce barriers to entry and result in lower prices for consumers.

The Guarantee places a dual obligation on retailers to acquire a mix of resources on behalf of their customer
demand that allows them to in turn supply electricity that is affordable, reliable and overall complies with
emissions reduction goals for the electricity sector. In particular, retailers are required to contract with
generators or demand response providers for a minimum level of dispatchable electricity where there is an
identified gap, with the emissions produced by that electricity not exceeding an agreed level. Bringing
together climate and energy policy in this way will allow the two to evolve and keep pace with each other,
which is important in light of the rapidly evolving power system.

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7 See Figure 3.1 (left-hand panel) in:
he%20National%20Energy%20Guarantee.pdf


9 In this report, ‘contract’, ‘firm-capacity hedge contract’ and ‘firm contract’ are terms used interchangeably unless
noted otherwise. The distinction between firm and ‘non-firm’ contracts is discussed in Appendix C.
The Energy Security Board’s modelling from November 2017 found that requiring retailers to contract for a certain level of dispatchable generation will increase the proportion of generation capacity contracted, which should lead to more competitive bidding in the spot market as generators are incentivised to bid as low as possible to increase their chances of being dispatched in order to cover their contracted capacity, resulting in lower spot prices. If the higher demand for contracts was not able to be met by existing resources due to their physical constraints, the demand would be met from new entrants (particularly fast-start resources), which improves system reliability and reduces the likelihood of extreme spot price events, lowering price volatility.

Appendix C contains further discussion of the types of contracts used in the NEM, and how entering contracts incentivises generators to be available and ready to generate, thereby delivering reliability of supply to consumers.
3 Emissions requirement: Energy Security Board design elements

3.1 Overview

This chapter discusses the design of the emissions requirement, other than the design elements for Commonwealth Government decision which are discussed in the next chapter. The emissions requirement design discussed in this chapter will be established through the Council of Australian Governments Energy Council (COAG EC) through the existing national electricity governance framework (see Chapter 6). The Energy Security Board is interested in feedback on the design set out in this chapter.

As discussed further in chapter 4, the Commonwealth Government is considering setting a trajectory of electricity emissions targets. These could be expressed in average emissions per MWh (tCO2-e/MWh), which retailers would be required to meet in respect of their load.

The emissions requirement would be implemented in 2020.

3.2 Applying the emissions requirement

3.2.1 Entities covered by emissions requirement

As discussed in the ESB’s November 2017 report, the entities covered by the emissions requirement will be each entity registered by AEMO as a Customer under the Rules (retailers and registered large users, together referred to in this paper using the general term ‘retailer’).

For each year for which electricity emission targets are set (referred to as a compliance year), each retailer will be required to meet the electricity emissions target in respect of its own load in that year. The calculation of a retailer’s load is discussed in section 3.2.2 below.

A retailer’s performance against the electricity emissions target will be determined in tCO2-e per MWh with reference to its load and the emissions associated with its contracted and uncontracted purchases in the compliance year, and could be adjusted to account for various factors as summarised in the following sections.

The emissions target compliance calculation would be performed following the reporting deadline for a compliance year.

Questions for stakeholder consultation

• What are stakeholders’ views on whether the compliance year should be a calendar year or a financial year, noting that EITE exemption processes under the RET use calendar years, whereas emissions reporting obligations relate to financial years?.

3.2.2 Calculation of load

In brief, a retailer’s load will be the number of MWh recorded by AEMO as being purchased by the retailer on the wholesale spot market in the relevant compliance year, in order to supply its customers (for retailers authorised by the AER under the National Energy Retail Law) or for its own use (for large users who are registered Customers under the NEL). This will be based on wholesale market settlement data.

In the event that the Commonwealth Government decides to exempt the electricity used for EITE activities from the emissions requirement, as discussed in section 4.3, electricity that a retailer sells for EITE activities in the relevant compliance year will be deducted from that retailer’s load.

Questions for stakeholder consultation

• What are stakeholders’ views on the process to calculate a retailer’s load.

3.2.3 Calculation of emissions per MWh – overview

The following provides a potential way in which the emissions per MWh of each retailer's load could be calculated for a compliance year. Each point is expanded on below, with stakeholder feedback invited on each aspect. The calculation could occur as follows:

- Determine the emissions associated with the retailer’s contracts where the emissions per MWh can be determined. This could include contracts between the retail and generation arms of a vertically-integrated retailer or power-purchase agreements.
- Determine the emissions associated with contracts where the emissions per MWh are not specified.
- Deduct the emissions associated with MWh sold by that retailer to other retailers or to intermediaries.
- After accounting for all of the above, determine the emissions associated with that retailer’s remaining load by applying a default emissions factor.
- Adjust the above for any deferral of compliance, any under-compliance (in excess of the deferral limit), or any over-compliance achieved in the previous year.
- Adjust for any voluntary ‘green’ programs. If the Commonwealth Government decides to exempt the electricity used for EITE activities or allow the use of offsets, adjust for any sales to EITE activities or for any eligible offsets.

Data reported under the National Greenhouse and Energy Reporting Scheme (NGERS) would be used for emissions calculations.

Questions for stakeholder consultation

- What are stakeholders’ views on how a retailer’s emissions should be determined?

3.3 Contracting and emissions

Retailers would report contracts of their choosing to demonstrate compliance with the emissions requirement. These contracts could, but need not, specify the generation source or emissions per MWh. Broadly speaking, the following three types of contracts could be used by retailers to achieve compliance with the emissions requirement.

1. Contracts that specify a generation source, which allows the emissions per MWh to be directly determined. An example of such a contract is a power-purchase agreement sold by a wind farm (with zero emissions).

2. Contracts that specify the emissions per MWh but do not specify a generation source. While such contracts do not currently exist, the design of the emissions requirement needs to allow for possible innovation in contract markets. An example of such a contract in future could be an existing exchange-traded contract with an emissions per MWh specification.

3. Contracts that do not specify either the emissions per MWh or a generation source. Examples include existing exchange-traded and OTC swaps and caps.

3.3.1 Contracts that specify a generation source

Contracts with specified sources are those that specify the plant or portfolio of plants that generate the MWh under the contract.

For these contracts, emissions are determined by multiplying the MWh settled under the retailer’s contract with the weighted-average emissions per MWh of the plants specified in those contracts. Information on generators’ contracting positions and MWh generated would be part of the registry (see Section 3.6.2), and could be used to confirm that contractual allocations do not exceed actual generation by the plant.

While specified-source contracts may provide greater assurance to retailers about the emissions associated with their electricity purchases, specified-source contracts are not standardised (i.e. the emissions

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11 Weighted-average emissions per MWh could be calculated in accordance with a standard methodology, such as AEMO’s Carbon Dioxide Equivalent Intensity Index under the Rules.
associated with a contract will depend on the plant that is specified in the contract). These contracts may therefore be less fungible and less liquid than the more standardised contracts discussed below. The ESB expects that specified-source contracts will form part of, but not all, the portfolio of contracts used by retailers to achieve compliance with the emissions requirement.

### Questions for stakeholder consultation

- What are stakeholders’ views on the methods for determining the emissions to assign to contracts where the generation source is specified?
- If the contract specifies a portfolio of plants and the plants have differing emissions profiles (eg some are zero-emissions plants and some are gas plants, used for firming the variable renewable energy), how should the emissions per MWh under the contract be determined?

#### 3.3.2 Contracts that specify emissions per MWh but not a generation source

Contracts could be developed that specify the emissions level for each MWh of electricity but are not linked to one specific generation source. Examples of such contracts could include those that pool together several generators with similar emissions within a region to create a more standardised contract that is more fungible and therefore easier to trade than contracts that link to one generation source.

Contracts could also take the form of a ‘stapled security’, where a specified amount of emissions per MWh is ‘stapled’ to those types of contracts currently in existence (such as OTC or Australian Securities Exchange-traded swaps).

If a contract specifies the emissions of the MWh to be settled under the contract, evidence of that level of emissions will be required in order for the purchasing retailer to report those MWh at the specified level in the registry for compliance with the emissions requirement.

Evidence could take the form of records of each MWh generated by a relevant plant. These records would be maintained in an independently-administered central database. The Clean Energy Regulator (CER) has a robust emissions and energy reporting system and automated data exchange with AEMO, which may provide a solid base for the functionality required. The records would show the emissions associated with each MWh, by linking to the generating plant’s generation and emissions profile. A contract with a specified level of emissions per MWh could be fulfilled by transferring the records of the relevant number of MWh at the relevant emissions level to the purchasing retailer’s account in the database.

This would prevent a generator or intermediary selling more MWh of generation at a particular emissions level than were actually generated. If a generator generates less than it has contracted for, only the MWh for which records have been transferred to the retailer in the database, rather than the contracted amount of electricity, would be counted by the retailer for the purposes of the emissions requirement. Contracts typically contain information on how non-compliance with the contract’s terms and conditions are to be dealt with.

### Questions for stakeholder consultation

- What are stakeholders’ views on how to determine the emissions per MWh to assign to contracts that specify an emissions level but do not specify a generation source?
- What are stakeholders’ views on how the contract market may evolve to support this type of compliance with the emissions requirement?

#### 3.3.3 Contracts that specify neither emissions per MWh nor a generation source

Examples of these contracts include those currently sold via intermediaries such as the Australian Securities Exchange (ASX), and those sold between retailers and generation businesses or intermediaries where the generation source is not specified. In this case, a deemed emissions level needs to be assigned. This level could be determined in different ways. The deemed emissions level could be determined by NEM region to align with current contracting practices. For example, the deemed emissions level for a particular type of contract (such as an ASX-listed swap) sold in a particular region could be calculated based on the emissions of those generators that sold that type of contract in that region in the previous year. Alternatively, all types of contracts sold in a particular region could be deemed to have the same emissions level.

For certainty throughout a compliance year, the deemed emissions levels used for that year could be based on calculations from the previous year.
Questions for stakeholder consultation

• What are stakeholders’ views on the appropriate emissions level to assign to contracts that do not specify an emissions level or generation source?
• What (if any) impact would these approaches to determining the deemed emissions level have on the liquidity and availability of those types of contracts?

3.3.4 Retailer-owned generation

Several retailers in the NEM also own generation assets, i.e. they are vertically integrated to some extent. The corporate structure and policies of a ‘gentailer’ may be such that the retail arm contracts with the generation arm, in which case the contracts could be reported as contracts with a specified generation source.

Where the corporate structure does not allow for this, the gentailer’s retail arm would be able to report, and count towards compliance, the MWh and tonnes of emissions from the organisation’s generation arm that remain after deducting the tonnes associated with the MWh from the relevant plant(s) that were sold under contract to other parties.

Questions for stakeholder consultation

• What are stakeholders’ views on how to deal with internal non-contractual arrangements between the retail and generation arms of a gentailer, for the purposes of the emissions requirement?
• What are stakeholders’ views on how to determine the emissions level to assign to contracts between the retail and generation arms of a gentailer?

3.3.5 Unhedged load

Subject to the design of the reliability requirement of the Guarantee, a retailer may choose not to hedge all of its load, or may hedge part of its risk through contracts that are not based on generation (e.g. weather derivatives). A default emissions level needs to be assigned to the portion of each retailer’s load that is not hedged with contracts based on generation (referred to here as ‘unhedged load’) since there may be emissions associated with the generation that supplies this load. This default emissions level could be:

• the weighted-average emissions per MWh of uncontracted MWh over a period of time\textsuperscript{12}
• the emissions per MWh of the highest-emitting plant operating in the NEM. This punitive level may increase the incentive on retailers to contract, rather than remain unhedged.

The default emissions level could also be applied where contracts with specified emissions levels have been sold by those generators whose plants and/or MWh of generation do not match the emissions levels specified in their contracts.

Questions for stakeholder consultation

• What are stakeholders’ views on how to determine the emissions level to assign to unhedged loads?

The emissions from retailers’ contracted, self-generated and unhedged loads will, together, determine a retailer’s overall emissions. A stylised example is provided in Box 3.1. For the avoidance of doubt, all the examples used in this chapter to demonstrate various aspects of the proposed design of the emissions requirement use hypothetical emissions values. These hypothetical values are not indicative of what will be actually applied under the Guarantee.

\textsuperscript{12} ‘Uncontracted MWh’ is defined as the difference between actual generation and the amount settled under contracts, for different types of generators.
Box 3.1: Example calculation of a retailer’s emissions per MWh

A retailer has a load of 1,350 MWh during a compliance year and the following contractual arrangements in place. The type of ASX contracts it buys has a deemed emissions level of 0.7 tCO₂-e/MWh. The default emissions level for unhedged load is assumed to equal 1 tCO₂-e/MWh.

<table>
<thead>
<tr>
<th>Arrangement</th>
<th>MWh covered</th>
<th>Emissions (tCO₂-e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Owns wind farms</td>
<td>100</td>
<td>0</td>
</tr>
<tr>
<td>Owns gas plant (emissions of 0.6 tCO₂-e/MWh)</td>
<td>600</td>
<td>360</td>
</tr>
<tr>
<td>Specified-source contract (hydro plant)</td>
<td>300</td>
<td>0</td>
</tr>
<tr>
<td>ASX contracts (emissions of 0.7 tCO₂-e/MWh)</td>
<td>200</td>
<td>140</td>
</tr>
<tr>
<td>Sells specified-source contract (hydro plant)</td>
<td>-200</td>
<td>0</td>
</tr>
<tr>
<td>Unhedged load (total load less hedged MWh)</td>
<td>350</td>
<td>350</td>
</tr>
</tbody>
</table>

Its emissions per MWh for that year would be its total emissions divided by its load in MWh: 850/1,350 = 0.63tCO₂-e/MWh

(For simplicity, the retailer in this example does not supply EITE activities and does not make use of flexible compliance options.)

3.4 Flexible compliance options

Providing flexibility in how retailers meet the emissions requirement could minimise instances of non-compliance, and also reduce the costs of the mechanism to retailers and their customers. This flexibility would allow retailers to manage variables such as unexpected generator outages and potential delays to the entry of new generators. Importantly, providing flexibility would not change the emissions outcome for the NEM. The required emissions outcome for the NEM would still be achieved over the medium to long term despite year to year fluctuations.

This section discusses three proposed flexible compliance options: carrying forward overachievement, deferring compliance to the next compliance year, and using offsets.

3.4.1 Carrying forward overachievement

It is proposed that retailers be permitted to carry forward a portion of a previous year’s overachievement, for use in the next compliance year. Allowing overachievement to be carried forward can incentivise investment when the market needs it and can enable retailers to achieve compliance at lower cost. It may also assist to smooth compliance costs between years with high availability of renewable resources (e.g. windy, high rainfall years) and years with low availability of such resources.

The RET has allowed unlimited overachievement to be carried forward by retailers to subsequent compliance years. The emissions requirement may also allow unlimited carry-over of overachievement or could limit the extent of carry-over of overachievement in order to provide greater incentive for overachieving retailers to offer more of their overachievement to the market. This could increase market liquidity and make it easier for all retailers to bring themselves into compliance.

A stylised example is provided in Box 3.2 where there is a pre-specified limit on overachievement (dubbed a ‘carry-over adjustment factor’).
Box 3.2: Example of carry-forward of overachievement

A retailer's load is 40,000 MWh in a compliance year, and its emissions for the compliance year are 20,000 tCO₂-e, resulting in an emissions level of 0.5 tCO₂-e/MWh. If the retailer's electricity emissions target for that year was 0.6 tCO₂-e per MWh, and the carry-over adjustment factor is 0.5 (meaning that half of any overachievement can be carried forward), its carryover amount would be calculated as follows:

\[(0.5 - 0.6) \times 40,000 \times 0.5 = -2,000\]

That is, in the following compliance year 2,000 tCO₂-e would be deducted from the retailer's emissions, making it easier for the retailer to meet the electricity emissions target in that year. The retailer could trade contracts associated with the remaining over-achievement of 2,000 to other retailers.

Suppose the retailer's load was 40,000 MWh in the following compliance year, and the emissions associated with its contracted generation were 24,000 tCO₂-e, the carry-over from the previous year would reduce the retailer's emissions to 22,000 tCO₂-e. The resulting emissions level would be 0.55 tCO₂-e/MWh.

If the retailer's electricity emissions target was 0.575 tCO₂-e per MWh in that year, the retailer would again have overcompliance to carry forward as follows:

\[(0.55 - 0.575) \times 40,000 \times 0.5 = -500\]

Questions for stakeholder consultation

• Should the emissions requirement allow for unlimited carry-over of overachievement or specify limits on the carry-over of overachievement?

• If limits are to be specified, what should those limits be and how should they be designed? For example, should the size of limits vary inversely with the size of the retailer's load? This could give more flexibility to smaller retailers.

• If limits are to be specified, how should overachievement in excess of the limits be treated? Should there be a process by which it is offered to the market?

3.4.2 Deferring compliance

Deferring a portion of the emissions requirement from one compliance year to the next would provide retailers flexibility as to the timing of the activities they need to undertake to comply with the emissions requirement without being in non-compliance in any one year. However, allowing too great a deferral may delay the necessary investment in the NEM, undermining the objectives of the Guarantee. Furthermore, retailers holding large liabilities carried over from previous years could risk the financial stability of the retail sector, and if a retailer carrying over a large liability becomes insolvent, it could make it more difficult for the emissions reduction target to be met.

Retailers could be allowed to defer up to a limit (for example 20 per cent of their emissions in a given compliance year, excluding any deferral from the previous compliance year) to the next compliance year. Providing a limited amount of deferral would provide retailers with sufficient flexibility while reducing risks to the objectives of the Guarantee.

A stylised example is provided in Box 3.3.

Deferral could happen automatically in the registry, and deferral up to the permitted limit would not result in any penalty or other enforcement action by the AER. Any under-compliance that exceeds the deferral limit would also be added to the retailer's emissions requirement in the next compliance year, but may in addition result in enforcement action by the AER (see section 3.6.4).

Box 3.3: Example of deferral to next compliance year

If a retailer's load is 40,000 MWh in a compliance year and its emissions are 25,000 tCO₂-e, its emissions level would be 0.625 tCO₂-e/MWh. If the electricity emissions target for the compliance year is 0.6 tCO₂-e per MWh, the amount of the retailer's deferral would be calculated as follows:

\[(0.625 - 0.6) \times 40,000 = 1,000\]

This is less than 20% of the retailer's emissions for the compliance year (calculated as 0.2 x 25,000). Therefore the retailer's emissions requirement for the next compliance year would be increased by 1,000.
tCO₂-e and the retailer would not be penalised in relation to the electricity emissions target for the initial compliance year. In the following year, the 20% limit on deferral would be calculated as 20% of the retailer’s emissions in that year less the 1,000 tCO₂-e deferred from the previous year.

Questions for stakeholder consultation

- What are stakeholders’ views on the deferral of compliance?
- Should all retailers be able to carry forward a fixed amount or should it be set proportionally to a retailer’s load? This could give more flexibility to smaller retailers than large ones. If so, would any provisions need to be introduced to prevent large retailers re-organising themselves as several smaller retailers in order to gain the benefit of the higher limit?
- If the limit on deferral should be a static percentage of load (rather than varying), what percentage is appropriate? That is, what percentage would provide the necessary flexibility without substantially increasing the risk that the overall emissions reduction target would not be met?

3.4.3 Use of offsets

If the Commonwealth Government determines that certain offsets may be used for compliance (see section 4.4), the National Electricity Law and Rules could provide details regarding the use of offsets for the emissions requirement. In addition, if the Commonwealth Government sets an overall limit on the use of offsets by the electricity sector, the Rules may address how to allocate that limit between retailers in the NEM.

If there was an absolute limit on offsets for each retailer, provisions could be needed to guard against the risk of large retailers splitting into several smaller entities to gain the benefits of obtaining relatively higher offset limits.

Consistent with the focus of the emissions requirement being to reduce emissions in the electricity sector, retailers could be required to use within-NEM opportunities before relying on offsets to bring themselves into compliance. For example, it could be the case that a retailer would not be permitted to use offsets for compliance in a particular year if it would have any over-compliance in that year before taking the offsets into account.

Questions for stakeholder consultation

If offsets are permitted by the Commonwealth Government:

- Should limits on individual retailers’ use of offsets be set at an absolute level, regardless of retailer size? An absolute limit would represent a greater proportion of a smaller retailer’s emissions than a larger retailer.
- Or, instead, should limits on individual retailers’ use of offsets be based on the size of retailers’ loads, such that offsets represent the same proportionate share of retailers’ emissions regardless of retailer size?
- What are the pros and cons of each of the above approaches?
- If limits on use of offsets are independent of retailer size, how should the risk of large retailers splitting into several smaller entities for the purposes of increasing their overall offset limit be addressed?
- What (if any) requirements to use within-NEM opportunities before using offsets are appropriate?

3.5 Interaction with voluntary ‘green’ programs

The design of the emissions requirement needs to account for the interaction with voluntary green programs. Some business and household consumers undertake voluntary action to reduce emissions associated with their electricity use. Voluntary action provides additional demand for renewable energy above mandatory government requirements. In doing this, the signal for investment in these types of electricity generation assets is further strengthened. A prominent example is the GreenPower program.

The emissions requirement could be designed such that voluntary programs like GreenPower are additional to the emissions requirement.
A stylised example of how a voluntary program can be treated as being additional to the emissions requirement is provided in Box 3.4.

**Box 3.4: Example of voluntary program additionality**

Assume a retailer has 100,000 MWh of load in a compliance year, including 10,000 MWh of electricity supplied to customers under a zero-emissions voluntary program. Its emissions are 60,000 tCO₂-e and its electricity emissions target is 0.7 tCO₂-e/MWh.

The retailer’s emissions for compliance purposes would be increased by 7,000 tCO₂-e to 67,000 tCO₂-e to ensure the additionality of the renewable energy purchased for the voluntary program. The increase is calculated as \((0.7 - 0) \times 10,000\).

As a result, the retailer’s emissions level would increase from 0.6 tCO₂-e/MWh to 0.67 tCO₂-e/MWh.

A retailer would need to report in the registry the MWh sold to customers under a voluntary green program each year and the emissions level promised under that program, e.g., zero emissions generation. In relation to GreenPower, the GreenPower administrators could be required to provide data to the AER on retailers’ sales of GreenPower products.

In the case of GreenPower, retailers would still need to surrender LGCs representing the additional electricity sourced from renewable energy generators.

**Questions for stakeholder consultation**

- What are stakeholder views on the interaction between the emissions requirement of the Guarantee and voluntary programs such as GreenPower?

### 3.6 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 Guarantee.

The primary aim of enforcement is to ensure policy objectives are met. 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 sanction: one that is proportionate to the offence, acts as a deterrent, and provides greater certainty that the policy objectives are to be met.

#### 3.6.1 The AER as the enforcement agency for the Guarantee

The AER was established in 2005 and enforces the laws for the NEM, and monitors and reports on the conduct of market participants and the effectiveness of competition. The AER is also the economic regulator of the electricity networks. This role currently extends to electricity networks in all jurisdictions except Western Australia. The AER operates under the *Competition and Consumer Act 2010 (Cth)* and is a part of the ACCC.

In light of the need to integrate the dual requirements of the Guarantee with the functioning of the energy markets, and the fact that the enforcement agency for the Guarantee would need to enforce requirements set out in the National Electricity Law and Rules (see chapter 6), the AER is considered best-placed to monitor and enforce compliance with both requirements of the Guarantee. In doing so, it will use information provided by agencies such as AEMO and the CER.

The AER already has access to a range of compliance tools under the NEL. The types of tools that are available to the AER under the NEL are discussed in section 3.6.4.

The AER would annually publish high-level compliance outcomes, such as the proportion of entities covered by the Guarantee that complied with the emissions requirement and the reliability requirement.

#### 3.6.2 Compliance registry

To monitor and verify a retailer’s compliance with the emissions requirement, a system will be needed to match the actual generation and emissions from power stations with the retailers that hold the right to count that output towards their emissions position. As retailers can hold a large number of contracts, this is likely to
be a complex task. The following sets out the design and operation of a potential compliance registry. The ESB invites stakeholder feedback on the proposed design and operation of the registry.

A registry could be developed to facilitate monitoring, reporting and verifying for the emissions requirement. This registry could be maintained by the AER and be the primary tool the AER would use to assess retailers’ compliance with the emissions requirement. It would be established for compliance purposes and would not be designed to operate as a trading platform.

To minimise the reporting burden, the registry could receive relevant information from other data sources such as AEMO’s dispatch engine and spot market settlement data, and data on power plant emissions from the CER’s emissions and energy reporting system.

Retailers would report in the registry the information from their contracts needed to match their load with a power station’s dispatch (see section 3.6.3 below).

The registry would track electricity output by power station, using AEMO’s dispatch data. This output would be matched to the emissions level of each power station as reported under NGERS and provided by the CER.

The registry would attribute each power station’s output, and the emissions associated with it, to retailers. The registry would also record how much electricity each power station sold to the wholesale market without a contract. The emissions level of each power station could be used to calculate the weighted-average emissions level of all uncontracted electricity in the system.

Retailers could access the registry at any time, allowing them to report and monitor their emissions position throughout a compliance year.

Retailers and generators will be able to view all data that relates to them, and the AER will be able to view all data. Data will be treated as confidential and the AER will use it for compliance purposes only.

Questions for stakeholder consultation
- What are stakeholders’ views on the need for a compliance registry? What are stakeholders’ views on its design?
- Are there alternative schemes that would allow retailers to monitor and verify compliance with the emissions requirement? How could these alternative schemes work?
- Are there any additional features which the registry should have?
- Should any of the data in the registry be made publicly available?

3.6.3 Reporting requirements for emissions requirement

Each retailer will report in the registry key contract details for those contracts the retailer wishes to count towards the emissions requirement. These details could include the counterparty, number of MWh settled under the contract, and the timing of the generation.

Retailers will be able to add and update information in the registry throughout the year. The flexible compliance options (carry-over of overachievement, deferral and the potential use of offsets) could operate automatically so there would be no separate reporting requirements for them.

Some contract reporting obligations may also need to be imposed on generators.

Questions for stakeholder consultation
- What types of information are likely to be required to be entered into the compliance registry in order for retailers to monitor and assess their compliance with the emissions requirement?
- Is information on generators’ contracting positions also required to be entered into the compliance registry, for the purposes of reducing the chance of either double-counting or attributing generation output to the wrong retailer?

13 This registry could also be used for the purposes of the reliability requirement.
3.6.4 Enforcement tools for emissions requirement

If, despite the flexible compliance options described in section 4.4, retailers fail to meet the emissions requirement or fail to report accurately, 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.

Potential enforcement tools, based in most cases on the AER’s current powers, are listed below (noting that these could apply in addition to the automatic carry-over of a retailer’s under-compliance with the emissions requirement in one compliance year to the next compliance year).

- **Culture of compliance**: Minimising non-compliance through informing, educating and engaging stakeholders is better than enforcement action after a breach has occurred.
- **Administrative undertakings**: Administrative resolutions are a more informal and less intrusive enforcement option which the AER uses 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 a business has taken (or agreed to take) appropriate steps to end the conduct and to remedy any harm done.
- **Infringement notices**: These will specify the nature of the contravention and the amount of the penalty that must be paid. The AER’s current practice is to publish all infringement notices.
- **Enforceable undertakings**: These are written statements from an entity that it will take specified actions (for example, entering into contracts in order to resolve a breach). It is proposed that the AER be given the discretion to approve such undertakings instead of issuing a penalty.
- **Institute civil proceeding**: The AER can initiate civil proceedings in the courts for alleged breaches of civil penalty provisions of the national energy laws:
  - **Injunctions**: A court may order an injunction requiring a person to do something, or desist from doing something.
  - **Civil penalties**: A court may order that an entity pay a financial penalty as a result of breaching its obligations. The definition of “civil penalty” in the NEL may need to be amended in order to provide for more meaningful upper limits on civil penalty amounts (as has been done in respect of rebidding civil penalty provisions).
- **Suspending or revoking authorisation**: As a final step, in cases of significant and repeated non-compliance, the AER may suspend or revoke an entity’s retail authorisation, preventing it from participating in the retail market. This would result in the emissions requirement being applied to the remaining retailers.

The primary approach should be to build a culture of compliance. Given that the Guarantee will be new to market participants, the AER will need to ensure that the appropriate information is easily available to retailers and that they understand the requirements and mechanism through which they can meet their requirements. This is in line with other regulatory regimes, such as the Australian Securities and Investments Commission’s work to build a culture of compliance in the insolvency market.

Questions for stakeholder consultation

What are stakeholder views on the proposed approach to compliance with the emissions requirement and particular:

- Whether this approach provides the appropriate drivers of compliance.
- The type of information the AER will need to access to ensure compliance.

14 Australian Securities & Investments Commission website, Media release - 16-146MR NSW liquidator successfully completes independent peer review, published 17 May 2016.
Other possible enforcement tools, such as increased prudential requirements or restrictions on accepting new customers while emissions requirements remain outstanding.

### 3.7 Other considerations

#### 3.7.1 Competitive markets

While issues of market power and competition are currently being considered more broadly, including through the ACCC’s Electricity Supply and Price Inquiry, the Energy Security Board considers that the design of the Guarantee should make sure that it does not unintentionally further entrench market power and create barriers to entry for smaller players.

The Energy Security Board’s November 2017 report discussed the state of market concentration in South Australia, and standard market share indicators and generation trends were presented. In addition, the report discussed mechanisms that could be used to address market concentration. However, the Energy Security Board considers that further consideration cannot be given to these issues until the design of the Guarantee is further developed.

**Question for stakeholders consideration**

- What are stakeholder views on how the Guarantee may impact on competitive market?

#### 3.7.2 Jurisdictional considerations

The Energy Security Board has considered how the Guarantee would apply in the ACT. While it is its own market in respect of retailing electricity, the ACT sits within the NSW region of the wholesale market. As the emissions requirement is a requirement on retailers, it would apply across a retailer’s total NEM load, regardless of the jurisdiction(s) in which its customers are located.

The Energy Security Board also notes that in Tasmania, there is a Tasmanian Wholesale Contract Regulatory Instrument, which sets out the rules surrounding the provision of Tasmanian electricity derivatives by Hydro Tasmania to other electricity market participants. However, Hydro Tasmania can also offer unregulated contracts to counterparties beyond this. Given that under this framework Hydro Tasmania is required to offer to retailers operating in Tasmania a number of contract products that are broadly consistent with the standard products offered in the NEM, the Energy Security Board considers that the emissions requirement will be able to operate in Tasmania as it would in the rest of the NEM.

Some jurisdictions have jurisdictional emissions or renewable energy targets and the interaction of these with the Guarantee will need to be considered by the COAG Energy Council.

**Question for stakeholders consideration**

- What are stakeholder views on the operation of the emissions requirement in particular jurisdictions?

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4 Emissions requirement: Commonwealth Government design elements

4.1 Overview

This chapter discusses the design of the aspects of the emissions requirement for which the Commonwealth Government has primary responsibility. These include the:

1. emission reduction target for the NEM, including the level and form of the target
2. treatment of emissions-intensive trade-exposed (EITE) activities, and
3. eligibility of offsets and any limits on the use of eligible offsets.

The Commonwealth Government is seeking feedback on these policy areas discussed below through the ESB’s consultation process.

4.2 Setting the electricity emissions target and review processes

4.2.1 Setting the sectoral emissions reduction target

Australia is part of the global climate agreement made in Paris in late 2015, which sets in place a framework for all countries to take climate action from 2020 onwards. Australia’s commitment under the Paris Agreement is to reduce its emissions by 26 to 28 per cent below 2005 levels by 2030.

Emissions reduction goals for the electricity sector must be balanced against other factors, such as providing affordable and reliable electricity supply. The Commonwealth Government’s target for the electricity sector for 2030 under the Guarantee is a 26 per cent emissions reduction on 2005 levels, consistent with the national target. The modelling commissioned by the ESB demonstrated that in delivering a 26 per cent reduction in emissions on 2005 levels, the Guarantee would reduce electricity prices while maintaining system reliability.

The Guarantee is an enduring mechanism with no fixed end date (unlike, for example, the RET which ends in 2030). As such, as time passes, future emissions reduction targets beyond 2030 will be required. The Commonwealth Government will consider targets for the emissions requirement beyond 2030 in the context of the regular five yearly reviews required under the Paris Agreement to ensure ongoing consistency with Australia’s international commitments. Section 4.2.4 provides more detail on the timing and process for setting future targets.

4.2.2 Form of the emissions target under the Guarantee

The experience of the RET has demonstrated that setting a target which does not self-adjust in response to changes in demand can result in a pace of transformation that was not intended or planned for. A target expressed as an absolute volume of emissions risks a similar experience to the RET – it would slow the rate of transformation if demand is lower than expected, or hasten it if demand is higher than expected.

The option the Commonwealth Government is considering is to express the target as a trajectory of annual average emissions per MWh levels (referred to as ‘electricity emissions targets’) for retailers in the NEM. The trajectory would be consistent with the 2030 emissions reduction target for the electricity sector of minus 26 per cent on 2005 levels.

This approach would set a target for the level of emissions per MWh for retailers in the NEM each year, but actual emissions would depend on total electricity consumption. Importantly, this approach would self-adjust to the level of demand, allowing for the transition to lower-emissions generation to occur at a stable pace that can be planned for. Regardless of whether demand is higher or lower than expected, the level of emissions per MWh retailers must achieve would remain unchanged.

Questions for stakeholder consultation – Commonwealth Government responsibility

- Stakeholder views are sought on options for setting the emissions targets under the Guarantee.
4.2.3 Forecasts and adjustments to the target

When setting the electricity emissions targets under the Guarantee, the Commonwealth Government will need to take account of future electricity demand in order to achieve the desired level of emissions reductions. Future electricity demand is published by AEMO each year. AEMO’s most up-to-date demand projection would be used at the time the electricity emissions targets are set for the Guarantee.

Exemptions for EITE activities (discussed in section 4.3) would also need to be taken into account when setting the electricity emissions targets to apply to non-EITE electricity, in order to achieve the intended emissions reductions. To do this, the Commonwealth Government would need to estimate the expected amount of electricity demand from EITE activities, and the associated emissions that are exempt from the Guarantee.

The Commonwealth Government needs to make a decision about how often the electricity emissions targets would be adjusted to correct for updates to the forecasts initially used.

The option the Commonwealth Government is considering is that the trajectory of the electricity emissions targets would not generally be adjusted to account for variations in electricity demand. This would reduce uncertainty that can arise from regular changes to the targets.

Instead, the decision about how much to adjust for previous variances between forecast and actual demand would be made in the context of setting future electricity emissions targets. The most up to date electricity demand projections and forecasts of EITE demand would be taken into account when setting future targets.

### Questions for stakeholder consultation – Commonwealth Government responsibility

Stakeholder views are sought on:

- Whether, and in what circumstances, electricity emission targets already set should be adjusted.
- The process for making any such adjustments to electricity emissions targets.

4.2.4 Timing and process for setting the electricity emissions targets under the Guarantee

The Commonwealth Government will initially set the electricity emissions target trajectory for ten years, from 2021 to 2030. The trajectory will be set before the commencement of the Paris Agreement in 2020.

As the Guarantee is an enduring mechanism, the process for setting future targets beyond 2030 must balance the objective of providing investment certainty with the flexibility required to meet future national emissions reduction targets set under the Paris Agreement.

Under the Paris Agreement, all countries are required to set their national targets every five years to build ambition over time. Australia’s 2035 target is due by 2025, its 2040 target is due by 2030, and so forth. The Commonwealth Government’s 2017 Review of Climate Change Policies set out a domestic policy review and refine cycle to align with these five yearly Paris reviews.

Consistency between Australia’s post 2030 international targets and the Guarantee’s post 2030 targets will provide coherence between domestic policy and international commitments. As such, the Commonwealth Government will set at least a further five years of targets under the Guarantee every five years, in a process aligned with the five-yearly review processes under the Paris Agreement. For example, the 2035 Guarantee target would be set in the context of Australia setting its 2035 emissions target under the Paris Agreement by 2025.

Extending the electricity emissions targets under the Guarantee by at least five years, every five years, will ensure the market has, at any time, between five and ten years of targets available to guide investment decisions. This approach has been demonstrated to effectively deliver energy sector investment in Australia. For example, the RET scheme provides less future information than this (giving industry between only one and 10 years of increasing future targets) and has delivered more than 10,000 MW of investment since its commencement.

To provide further investor certainty, changes to the target trajectory by the Commonwealth Government could only apply with five years’ notice. For example, in 2025, no changes to targets from 2026 to 2030 could be made.
Questions for stakeholder consultation – Commonwealth Government responsibility

- Stakeholder views are sought on the proposed timing for updating the electricity emissions targets, including a five-year notice period.

4.2.5 Geographic neutrality

Industry stakeholders strongly support a nationally coordinated and consistent approach to reducing emissions in the electricity sector. Uncoordinated and inconsistent policies across different jurisdictions could result in inefficient investment decisions, a greater compliance burden for the electricity sector and increased costs to consumers and the economy.

As such, to ensure a coordinated approach, the emissions element of the Guarantee will apply consistently NEM-wide. Each year there would be a single electricity emissions target under the Guarantee that will apply across all jurisdictions in the NEM.

Consistent with the RET, the Guarantee will not prescribe any specific minimum or maximum levels of low emissions generation that are required within any particular jurisdiction. Instead, retailers will be able to meet their emissions requirements from across the NEM. Making the emissions element of the Guarantee geographically neutral allows the industry to find the most efficient outcomes and reflects the fact that to address climate change, it does not matter where the emissions abatement occurs.

Some jurisdictions may opt to pursue state-based policies to encourage investment in low-emissions generation in their state such as to achieve investment or employment policy objectives. These policies may change the geographic distribution of investment within the NEM. In this circumstance, the electricity emissions targets would remain unchanged and retailers contracting with generators receiving subsidies through state renewable energy schemes would be able to count their generation towards meeting emissions requirements under the Guarantee. The reliability requirement of the Guarantee would ensure that reliability needs are still met across jurisdictions, including in adjacent interconnected states.

The approach to state renewable energy schemes would be consistent with the interaction between the emissions requirement and the RET, where retailers would be able to contract with RET-eligible generators and count that generation towards meeting their emissions requirement under the Guarantee.

Abatement from the RET and state schemes already in place are already accounted for in business-as-usual emissions levels and would therefore be taken into account when setting the electricity emissions targets under the Guarantee.

Questions for stakeholder consultation – Commonwealth Government responsibility

- Stakeholder views are sought on the proposed approach to setting the electricity emissions targets under the Guarantee and interaction with state renewable energy schemes.

4.3 Treatment of EITE activities

4.3.1 Preserving Australia’s international competitiveness

EITE businesses carry out energy intensive activities to produce outputs that are exposed to competition from international trade. Since 2009, under the RET, EITE activities have been exempt. In 2015, this exemption was increased to 100 per cent.

To maintain consistency with the RET, the Commonwealth Government is of the view that electricity used to carry out EITE activities should be effectively exempt from the emissions requirement. The process for accessing exemptions and eligibility requirements for EITE businesses could be consistent with the existing arrangements under the RET scheme (see Box 4.1).

To achieve the desired level of overall emissions reductions, non-EITE electricity would need to make up the difference. To do this, the electricity emissions targets would need to be adjusted accordingly. This adjustment could be undertaken as part of the target setting process as discussed above.
4.3.2 What electricity could be exempt

The Commonwealth Government's intention is to exempt all electricity used to conduct an EITE activity from the emissions requirement under the Guarantee, consistent with the approach established under the Renewable Energy (Electricity) Act 2000 (the RET Act) from 2020 onwards (see Box 4.1).

**Box 4.1: EITE exemptions under the RET from 2020 onwards**

EITE activities eligible for an exemption are established in Part 3A and Schedule 6 of the Renewable Energy (Electricity) Regulations 2001 (the RET Regulations). Amendments were made to the RET Regulations on 14 December 2017 to include the addition of an ‘electricity use method’ for calculating exemptions for EITE activities.

From 2020, the ‘electricity use method’ will enable the Clean Energy Regulator (CER) to issue exemption certificates that prescribe a formula for calculating the amount of MWh used in a calendar year to carry out an EITE activity at a site. Audit requirements and the CER’s checks ensure that the method in the certificate can accurately estimate the electricity used.

The EITE business is then able to provide this certificate to its electricity retailer in exchange for a better price for its electricity. The retailer can use the method defined in the certificate to calculate the amount of electricity that is exempt from liability in that calendar year.

To retain consistency, all EITE activities eligible for an exemption under the RET could be eligible for an exemption from the emissions requirement under the Guarantee. The Commonwealth Government could allow EITE businesses to apply to the CER for an exemption under the Guarantee, in addition to their application for an exemption certificate under the RET.

The CER could establish a process to calculate the exemption, consistent with the ‘electricity use method’ under the RET. The process could take into account any required adjustments to the method based on differences between the RET and the Guarantee, including any variation in the compliance period and the scope of electricity covered under the two policies.

Retaining the CER as the regulator responsible for EITE exemptions would avoid creating inconsistencies in the process for exemption calculations and would minimise regulatory burden on businesses applying for an exemption. The National Electricity Law and Rules would need to be amended to recognise any exemption certificates issued by the CER for the purposes of compliance with the emissions requirement.

**Questions for stakeholder consultation – Commonwealth Government responsibility**

- Stakeholder views are sought on issues to be addressed in exempting EITE activities from the emissions requirement of the Guarantee

4.4 External offsets

The Commonwealth Government is considering whether retailers should be able to use offsets external to the electricity sector as a flexible compliance option to meet the emissions requirement. If they were to be eligible, the Commonwealth Government is considering whether any conditions or limits should be in place on the volume and types of offsets that can be used.

If the Commonwealth Government decided that offsets were eligible, a retailer could be permitted to purchase and surrender offsets such as Australian Carbon Credit Units (ACCUs) from domestic markets, or international units of an equivalent standard in order to meet its emissions requirement. The retailer would be permitted to reduce its portfolio’s emissions by one tonne for each offset purchased and surrendered.

Allowing retailers the option to use offsets to meet the emissions requirement would increase the flexibility of the scheme.

If offsets were allowed into the Guarantee, the Commonwealth Government could place a limit on the volume of offsets that could be used for compliance with the emissions requirement across the NEM. This could be a percentage limit (for example, 10 per cent of the electricity emissions target) or an absolute limit (for example, 500,000 units of offsets per year).

In its final report on the 2017 Review of Climate Change Policies, the Commonwealth Government provided in-principle support to the use of high quality international offsets issued under the Paris Agreement to meet Australia’s emissions reduction goals, subject to further analysis on appropriate quality and quantity restrictions. However, a decision has not yet been made on the use of international units under the
Guarantee. The governing framework for the use of international units under the Paris Agreement has yet to be established.

**Questions for stakeholder consultation – Commonwealth Government responsibility**

Stakeholder views are sought on whether retailers should be allowed to use external offsets to meet a proportion of their emissions requirement. In particular, views are sought on:

- Whether there is a strong rationale for the use for offsets within the Guarantee
- The impact allowing offsets would have on investment under the Guarantee
- If offsets were to be used to help achieve compliance with the emissions requirement, what would be an appropriate limit for their use?
5 Reliability requirement

5.1 Overview

This aspect of the Guarantee involves creating a requirement on retailers to enter contracts related to dispatchable resources. This reliability requirement would make clearer the value of being dispatchable, both on the supply and demand side. Maintaining an adequate level of dispatchable resources is necessary for the secure and reliable operation of the power system.16

Chapters 3 and 4 of this initial consultation paper discussed the creation of an emissions requirement. However, meeting the emissions requirement only may not necessarily result in an appropriate amount of low-emissions dispatchable resources being in place in each NEM region. Therefore, the incentive to invest in dispatchable resources is created by the reliability requirement, in combination with other existing and new mechanisms in the NEM (see appendix B). The extra capacity will give AEMO more options in how it manages the system to deliver the required level of reliability.

The Energy Security Board welcomes stakeholder feedback on all aspects of this chapter including, but not limited to, those identified in the ‘questions for stakeholder consultation’ boxes.

The process surrounding the reliability requirement is expected to commence in 2019.

5.2 Designing a reliability requirement

The design of the reliability requirement is aimed at incentivising retailers to invest in resources that improve the reliability of the power system. If retailers fail to make these investments by a prescribed time, AEMO will be able to procure resources to fill any outstanding gap.

The reliability requirement builds on existing NEM and financial market arrangements that facilitate investment in capacity. As outlined in chapter 2, these arrangements relate to the use of hedging or derivative contracts by market participants to manage risks associated with wholesale spot exposures. The ESB considers that building on existing arrangements in the design of the reliability requirement is advantageous since these are already understood by market participants, market bodies, governments and other stakeholders, having existed since NEM commencement. The use of existing arrangements also minimises the time and costs associated with implementation, since new mechanisms and products do not need to be developed.

The Energy Security Board considers there are eight high-level steps that form part of the reliability requirement:

1. **Forecasting the reliability gap:** AEMO forecasts whether the reliability standard is likely to be met (or not) in any NEM region over a forecast period.
   
   AEMO will work with the Reliability Panel on the appropriateness of the current 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.

2. **Updating the reliability gap:** AEMO will update the forecasts of the reliability gap over time, as the market changes e.g. to reflect a notification of a retirement of a particular generator.

3. **Triggering the requirement:** If a reliability gap has been identified, the market would be expected to react and start to invest in new capacity or offer additional existing capacity to the market. There will be a point in time in advance of the forecast reliability gap at which the reliability requirement is ‘triggered’ and retailers are then required to respond.

4. **Qualifying instruments:** Retailers will be incentivised to make investments or enter into contracts that underpin new investment that alleviate the identified gap. In order to respond to any identified gap, participants will need to know the instruments that will ‘qualify’ for meeting the reliability requirement.

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16 The Guarantee will not directly address the provision of a range of services including system strength, inertia, ramping and flexibility, which are required for a secure system. The Energy Security Board considers that additional market design changes, such as new tools and mechanisms, will be necessary to address these. How the Energy Security Board and market bodies are addressing these matters is set out in section 5.2.
requirement. Retailers will be required to demonstrate that they have entered sufficient eligible contracts to cover their share of the peak demand requirement at the time of the reliability gap.

5. **Allocating the requirement**: If there is an identified gap, this will need to be ‘allocated’ to each retailer so that each retailer knows how much it is has to comply with.

6. **Compliance**: The AER will assess whether retailers have met their reliability requirement.

7. **Procurer of last resort**: If retailers do not meet the requirement by the compliance date, AEMO will procure resources to fill any remaining gap.

8. **Penalties**: Penalties are assigned to retailers that have fallen short of their reliability requirement.

There are various design options within each step and these are discussed below.

### 5.3 Forecasting the reliability gap

AEMO will undertake modelling to forecast the future requirements for reliability in each NEM region. The purpose of the modelling is to provide information to the market about the size of any forecast ‘gap’ in reserves. The gap will need to be expressed in terms of MW in a region, at a particular point in time for a particular duration.

Through its existing MTPASA and ESoO processes AEMO already provides information to market participants on the outlook for supply and demand and the likelihood of breaching the reliability standard in each region over two years for the MTPASA and 10 years for the ESoO. These forecasts use a combination of industry inputs (e.g. generation capacity) as well as stochastic modelling of supply and demand. These processes are further explained in Box 5.2 below.

Through this forecasting of any reliability gap, AEMO will undertake a forward assessment of the following variables for each region of the NEM:

- the amount of capacity that is forecast to exist in each region (‘supply’) on a 10% POE\(^{17}\) day, based on its projections, at various points in the future. This will take into account closure announcements by participants, the likelihood that a particular resource will be there in a peak period, and other information provided to it by market participants in relation to planned maintenance and outage,

- the amount of demand forecast for a 10% POE day.

The difference between these two amounts will determine the extent of the projected reliability ‘requirement’ or ‘gap’ (‘forecast period’). In developing this forward assessment, AEMO will publish its methodology, assumptions and draft projections for public consultation. This modelling will be done against the reliability standard that is reviewed by the Reliability Panel every four years, and which is currently 0.002 per cent.\(^{18}\) The modelling will use MW availability from market participants, with AEMO then forecasting outcomes probabilistically (i.e. taking into account AEMO assumptions about partial outages, forced outages, demand outcomes, inter-regional transfer capabilities etc).

If AEMO identifies that there is an expected breach of the reliability standard i.e. a ‘gap’, AEMO will provide further information as follows:

- region where the gap is forecast to occur, and commencement and cessation of the gap
- size of the gap expressed in terms of MW of additional capacity required to meet the reliability standard

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\(^{17}\) POE, or probability of exceedance, refers to the likelihood that a demand forecast will be met or exceeded. For example, a 10% POE forecast refers to that level of demand that is likely to be exceeded only once in every 10 years, and therefore indicates demand under 1-in-10 year conditions.

\(^{18}\) As noted above AEMO will work with the Reliability Panel on the appropriateness of the current 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.
• if applicable, change in gap since last reported and factors driving this change e.g. gap has decreased due to commissioning of new generation capacity or reduction in forecast demand in region.

Information from this forward assessment would be provided to the market for some period of time prior to the requirement formally being triggered. The information provided through this process would signal the appropriate level of capacity that is needed for a reliable supply, and so would signal to market participants about whether or not more investment is required in a particular region.

If a ‘gap’ is forecast, the market will have the opportunity to address the gap, either by building new capacity (either generation or demand response), delaying retirement decisions or shifting outages. The ESB expects that the market should respond to these forecasts and deliver the capacity, by adjusting their investment and retirement decisions to avoid the requirement being triggered. If the requirement was triggered, retailers would face the uncertain costs associated with AEMO procuring resources to close the gap (discussed below in section 5.3) along with any other potential enforcement action undertaken by the AER. These procurement costs are likely to be larger than what the retailer would have sourced the capacity for itself, and so imposes a significant incentive on the retailers to fully close the gap. Retailers will also be incentivised to contract for multiple future years at a lower cost if it deems that that is efficient. If its exposure in consequent years is less, then it can on-sell this to others.

5.3.1 How far ahead should the gap be forecast?

The forecast should cover a fixed and known period forecasting horizon, be updated to reflect changes in market conditions and use a transparent and replicable process (discussed further in section 5.3.2 below). The Energy Security Board considers that the forecasting horizon should provide retailers enough time to make decisions in response to the potential reliability gap identified but should not be so long that forecasts are too uncertain.

The Energy Security Board proposes that the forecasting horizon for the purposes of the reliability requirement should be somewhere between 2-3 and 10 years. These timeframes not only give the market sufficient time to respond; it would also align with the existing processes of the medium-term projected assessment of system adequacy (MTPASA), currently using a 2 year forecast horizon, or the Electricity Statement of Opportunities (ESoO), using a 10 year forecast horizon, and of course it would be open to select a timeframe in between these. Box 5.1 explains the ESOO and MTPASA processes.

A forecast horizon of 2-3 years would be more appropriate if the risk of reliability shortfalls is low and their occurrence irregular and short-lived. This timeframe would support a dynamic and responsive investment and operational environment and the existing MTPASA tool could be adapted for this horizon.

Alternatively, a longer forecast horizon of up to 10 years would be more appropriate if it was expected that the transition of the generation mix is likely to cause longer and deeper reliability gaps that require longer planning horizons for retailers to mitigate. Such an approach could use the existing ESOO or MT PASA tools, or a combination thereof.

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Box 5.1 What is ESOO and MTPASA?

**ESOO – Electricity Statement of Opportunities**
The ESOO is a comprehensive assessment of the future supply-demand balance over a ten-year outlook period. The purpose of the ESOO is to provide information to potential investors, market participants and governments on the supply-demand balance in each region of the NEM, the level of projected unserved energy (USE) if any, so as to highlight opportunities for investment in generation.

The most recent ESOO provides a projected outlook to 2026-27 of supply adequacy under a number of scenarios including: the impact of additional renewable generation in response to Australia’s federal and state renewable energy targets, and potential generation outage events that may challenge reliability of supply.

**MTPASA**
The PASA is a comprehensive program for the collection and analysis of information in order to assess the medium term and short term power system security and reliability of supply prospects.

The assessment of power system security and reliability in the MTPASA process is based on comparing the medium term capacity reserves available against the required levels determined in the Reliability Standard. It
is a transparent, well-understood process. In early 2018 AEMO will move to a probabilistic approach to calculating the MTPASA.

Medium term capacity reserve, is the aggregate amount of generating capacity indicated by the relevant generators as being available any time on a particular day during the period covered by the MTPASA, and which is assessed by AEMO as being in excess of the capacity requirement to meet the forecast peak load, taking into account the known or historical levels of demand management. Information is provided by market participants on a continuous basis and reported by AEMO on an aggregate basis every 3 hours.

5.3.2 How should the gap be forecast?

The Energy Security Board considers it important that the inputs used in the forecast are transparent, and the methodology used to determine the forecast is clearly understood. It is important that market participants have an opportunity to dispute and contest assumptions and parameters that are being used given that the results of this exercise may ultimately lead to a regulatory obligation and associated compliance risks. Therefore, in developing this forward assessment, AEMO will be required to publish its methodology, assumptions, and draft projections for public consultation.

An existing process, such as the MTPASA or ESoO could be adapted for the purpose of establishing a reliability requirement. However, ESoO-type forecasts may be better suited to the longer-term forecasts compared to MTPASA forecasts which are focussed around operational scheduling of outages.19

Alternatively, a new process could be developed for the reliability requirement. This would be the best course of action if adapting existing processes would undermine the purpose of the existing process, or if it would be faster and cheaper to develop a new process rather than amend existing processes. However, these benefits would have to be balanced against any costs (both time and resources) associated with the development of a new process.

Questions for stakeholder consultation

- What are stakeholder views on the length of the forecasting period?
- Should the existing ESoO and MTPASA forecasting processes be adapted for determining the gap, or should a separate bespoke process be developed?
- What elements of the current MTPASA and EsoO processes should be reviewed in light of the potential for the process to lead to a compliance obligation? E.g. how should AEMO treat inputs from generators such as their forced outage rate or summer capacity if these assumptions could lead to a triggering of an obligation?
- Should AEMO be able to determine assumptions independently or should responsibility for the accuracy of assumptions be placed on the market participant?
- How should the forecasting methodology and assumptions be consulted on?

5.4 Updating the reliability gap

AEMO will update the forecasts of the reliability gap over time, as the market changes and more or different information becomes known. For example, if a generator announces its retirement in 3 years’ time, this information will be incorporated into forecasts. Or, after observing changed forced outages rate assumptions after a run of extreme weather days, AEMO will change its assumptions that feed into its model when developing the reliability gap.

How often the updates occur depends somewhat on what process is being used for forecasting the reliability requirement. Regular updates of the projected extent of any reliability gaps for a given forecast period are desirable since they provide information that is most up to date. However, forecasts that change too often will deter investment as retailers will not be certain what they are aiming at.

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19 The Energy Security Board considers that this could be extended to three years, which would better align with the three year generator notification of closure rule change that is the subject of a Finkel recommendation. This change to the MT PASA would likely be beneficial regardless of what happens with the Guarantee. The Energy Security Board will therefore work with the market bodies to progress a rule change to be submitted to the AEMC on this basis.
The exact frequency of the updates depends on the length of the forecasting horizon. A forecasting horizon of 10 years lends itself more to an annual or quarterly update (potentially with more ad hoc updates if a material change), whereas a 2-3 year horizon makes weekly or monthly updates more achievable.

**Question for stakeholder consultation**
- How frequently should the forecast be updated?

### 5.5 Triggering the requirement

After the reliability gap has been forecast there will need to be a point in time during the forecasting period when a forecast reliability gap will trigger the reliability requirement. Participants will then be required to respond as detailed below. If a gap is forecast, the period between the start of the forecast horizon and the trigger point is effectively a ‘warning period’ that allows market participants to alleviate potential shortfalls without the imposition of the requirement. For example, a ten year forecast of a gap for a given period coupled with a three year trigger provides seven years for participants to ‘work it out’.

Despite a warning period, any updates confirming the forecast shortfalls for the given period would be accompanied by a market notice from AEMO. This would provide market participants with notice and opportunity to adjust their generation availability and other inputs to alleviate any forecast shortfall appearing in this time horizon. However, if after a period of time the market hasn’t responded, then the reliability requirement will be triggered.

The Energy Security Board considers the possible trigger periods can fall into two camps:
- short-term i.e. somewhere between 3 months – 1 year ahead of the forecast gap.
- long-term i.e. somewhere between 3-5 years ahead of the forecast gap.

Deciding the trigger period involves a trade-off between the accuracy and completeness of the information available at the point in time and the lead time of potential responses to the gap.

A short trigger period would allow for more current and complete information than a longer period. In other words, the outcomes observed are more likely to eventuate compared to a longer-term trigger period. For example, as the NEM moves closer to the time where the reliability gap is forecast to occur, generators will have greater visibility and certainty over the condition of their plant and availability of fuel. But, a short trigger period reduces the potential responses that AEMO can undertake to manage the forecast gap if retailers do not respond which means that the responses available to AEMO will typically be more limited and likely to be more expensive. For example, AEMO would likely only be able to use demand response, diesel generators, batteries or mothballed generators that would not otherwise have been in the market to cover the gap. This potentially increases the costs of the resources used and may be inadequate if the reliability requirement is large.

A longer-term trigger would enable retailers to respond with longer-term options such as new investments. But, having a long trigger period may undermine market responses since retailers may prefer to defer investments and wait and see if the forecast changes or may prefer AEMO to close any gap (see section 5.10 and Box 5.3 above).

The length of the trigger could affect the incentives associated with the ‘warning period’ referred to above. For example, if a large generation plant provides three years notice of closure and this results in a forecast gap from its projected date of closure, then the reliability requirement could be triggered immediately if the trigger period was three years or more. This would minimise, or at the extreme, completely remove, the incentives in the warning period that market participants have to reduce the gap.

There is a question about whether a multi-year gap would trigger a multi-year obligation on a retailer, or would the gap be addressed one year at a time. There are pros and cons with each approach. One year at a time would allow for new information that could change the forecast supply-demand position in the future and so would prevent over-investing in resources. Conversely, solving a significant gap extending over many years in a piecemeal fashion may lead to higher costs and potentially supply shortfalls.
There is also a relationship between the length of the trigger period and the selection of the compliance point. There needs to be sufficient time between the trigger and compliance point to enable action by retailers and sufficient time between the compliance point and the period in question to ensure there are a range of potential responses that AEMO can undertake to manage the forecast gap. This is discussed further in sections 5.8 and 5.10 below.

**Question for stakeholder consultation:**

- What trigger point would be most appropriate and proportionate to the identification of the reliability gap?
- Should a multi-year gap trigger a compliance requirement in only the first year of the gap or over the full duration of the gap?
- What is the minimum feasible time period for the market to alleviate a potential shortfall?
- If the length of the trigger period is such that the market is not given this minimum feasible time, is it appropriate for the Guarantee to contain the flexibility to have a shorter term trigger to provide sufficient time for the market to have an opportunity to respond to the shortfall?

### 5.6 Qualifying instruments

In order to respond to any identified gap, participants will need to know what instruments will “qualify” for meeting the reliability requirement. Retailers will be required to demonstrate that they have entered into sufficient eligible contracts to cover their share of the peak demand requirement at the time of the reliability gap.

#### 5.6.1 What contracts will be eligible?

Once the reliability requirement is triggered and the gap assigned, retailers will have an obligation to make sure that their share of the peak demand requirement, at the time of the gap, is covered by ‘eligible contracts’. The type of contracts that are eligible should be set out prior to the requirement being triggered in order to provide certainty to market participants about how the requirement will work.

As noted in chapter 2, retailer’s management of the financial risks associated with their spot market exposures occurs via the use of exchange-traded and over-the-counter (OTC) swap and cap contracts. These contracts are cash-settled, meaning there is no obligation under the contract to generate; instead, as discussed in Appendix C, a generator’s incentive to generate, at a particular time, typically arises from the need to earn spot market revenue to protect a sold contract position. In addition to OTC and ASX swap and cap contracts, retailers also use the following risk management options:

- ownership of physical assets
- bespoke financial contracts, such as options, callable hedges, collars, Asian options
- power purchase agreements (PPAs)/off-take contracts with wind and solar generators. These are sometimes referred to as generation-following hedges and are discussed further in Appendix C
- Settlement Residue Auction units, to facilitate hedging between NEM regions
- demand response agreements
- weather derivatives
- generator outage insurance
- a prudent level of residual spot exposure.

Each retailer uses a different combination of the above to manage the financial risks associated with selling electricity, according to the businesses’ risk appetite and financing arrangements.

The ‘physical backing’ of each of the above options varies. ‘Physical backing’ is a reference to being able to link the contract to the physical plant or portfolio of plants that generate the MWh under the contract. Some of these, by definition, are directly linked to a physical asset (ownership, PPAs and demand response) – and so are directly physically backed - while others may not have any sort of link to physical assets (weather derivatives, outage insurance).
Exchange-traded and over-the-counter (OTC) contracts (e.g. swaps, caps) fall somewhere in between physically-linked contracts and spot price-linked contracts as it is prudent for the sellers of these contracts to associate the sale of the contract with a physical asset even when these contracts do not impose an obligation to generate. The financial incentive to be available when the market needs it (i.e. when spot prices are high) means that the types of contracts these generators supply depends on how dispatchable their output is. For example, non-dispatchable generators like wind and solar may not generally sell (‘caps’) as these generators cannot be sure that they can generate to fund the payments required under this type of contract; but they likely will only sell fixed-price ‘swaps’ (and buy a cap to manage the risk associated with this). In contrast, gas and hydro plants typically sell both caps and swaps. In this sense, these financial contracts are still ‘physically backed’ and so assist with financing investment in dispatchable capacity, even though they do not specify a source.

Furthermore, while credit-worthy entities (typically, banks and other financial institutions) can and do sell financial contracts without actually owning any generation, much of the activity that is undertaken by these entities supports the liquidity in the contract market through essentially holding covered positions; that is, a sale of a financial contract to, say, a retailer is offset by the purchase of the same contract (though perhaps at a lower price, in order for the intermediary to earn a fee for their services) from a generator.

The degree to which a contract is physically backed will provide assurance that the reliability requirement will promote investment and provide incentives for the continued operation of physical assets. There are four ways that can be considered:

- certain types of financial contracts will be considered to be eligible contracts
- financial contracts that are ‘certified’ as being reconciled back to a physical source
- contracts will need to demonstrate that the generation or demand response, the subject of the contract itself, was sourced from a dispatchable generator or user
- physical ownership of generation assets as part of an integrated retail and generation portfolio.

A combination of the above approaches can be used.

**Financial contracts**

The benefits of accepting that the physical backing associated with certain types of existing financial contracts (including exchange-traded and OTC contracts) provides appropriate levels of assurance include:

- it is consistent with the existing arrangements (described in Chapter 2 and Appendix B), which makes it less likely to distort market participant behaviour and easier to implement;
- there could be a reduced administrative burden to monitor compliance because the metrics that would need to be reported to the AER are likely to be readily available to the reporting businesses. There may be a case to exclude purely financial instruments (such as weather derivatives) as they are unlikely to result in investment in or provide incentives for generation. If a more financial approach is adopted, then there may be a need to also ensure that generators are not then incentivised to manage their financial risk with non-physical products (e.g. weather derivatives).

Therefore, one way in which this could be given effect is that the only options that would be eligible would be swaps or caps. These are existing financial contracts that are traded in the market and so no new instruments would be required. Further, these instruments are clearly identifiable as a “cap” or a “swap” – both the OTC and ASX markets trade these products. These contracts provide electricity purchases with insurance against high prices. For example, the standard contract traded in the market is a $300 cap. This means the seller of a cap is required to pay to the buyer the difference between the spot price and

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20 Or they may sell them on a purely financial basis
21 To streamline the process, one option could be that the AER conducts a standardised survey, whereby retailers report metrics on their hedging position. This is relatively common in other sectors, such as financial stress testing by banks. Alternatively, the retailers could be asked to enter details of their contracts through the registry established for the emissions requirement, which the AER would be able to access.
$300/MWh every time the spot price exceeds $300/MWh during the specified contract period. Therefore, use of these contracts should provide sufficient physical backing to assist with directly driving dispatchable capacity.

As highlighted in Chapters 1 and 2, the development of the Guarantee will need to be done in concert with the development of a demand response mechanism for the wholesale electricity market to ensure that any demand response products developed also qualify for compliance under the Guarantee.

**Certification of financial contracts**

Building on the above way of demonstrating compliance, there could be a certification of financial contracts. This would have the benefit that from compliance purposes, the contract can uniquely be identified with a particular physical generator i.e. there is a stronger link between the financial contract and the physical asset, compared to above, which will reduce the risk of double counting. For example, OTC contracts specify a buyer and a seller so can be used to identify the source, but because they are financially settled can be sold multiple times against the same physical generator. For example, a 500 MW generator could sell 500 MW of caps to one retailer, buy 500 MW of caps from a generator, and then sell 500 MW of caps to a second retailer. The reliability requirement needs to avoid double counting so there needs to be a mechanism to tie the retailer contract to the physical capacity available.

This could be achieved through allowing financial contracts to be certified against installed physical capacity. In this example, only 500 MW can be certified so the two retailer contracts would need to be either scaled to match the total, or the contracts varied so that only one retailer could certify its contract. Under this approach, only OTC swaps, caps and PPAs would be eligible to be certified, and may lead different classes of contract under each category. Contracts which do not specify sources such as futures or that are contingent on exercise such as options would not qualify for certification unless a mechanism could be established to link futures volumes to the physical backing. This could however have the impact of limiting liquidity in the financial markets which would be counter to the objectives of the Guarantee.

In addition, under a certification approach, because not all energy sources may be considered equally, a detailed methodology outlining how the ‘firmness’ of the energy source will be determined for the purposes of compliance e.g. adjusting how much capacity a wind farm will provide in order to capture its intermittent nature; considering how ‘firm’ demand response is. Similarly, it would need to be considered how vertically integrated businesses are treated (see section below). This may need to be consistent with any assumptions made by AEMO when forecasting the reliability requirement.

**Specific physically backed contracts**

This approach would only allow certain types of contracts to qualify to be able to demonstrate compliance such as existing PPAs and demand response contracts. The benefit of this approach is that it would provide more assurance that the required investment that is needed to cover the gap is actually occurring.

This approach would potentially necessitate a fundamental change to the contract market, imposing significant costs on participants, and reducing liquidity. It also has the potential to exacerbate existing market structure issues, and associated concerns about the competitiveness of retail markets.

The Energy Security Board does not prefer this approach as a stand-alone option.

The Energy Security Board notes that, to the extent there is a desire for increase assurance of physical availability, there are a range of other possible reforms that could provide market participants and AEMO with greater certainty around day-to-day operational outcomes. These are being progressed through other work streams of the market bodies, as described above in section 5.2. These work streams include improvements to forecasting and introduction of a day-ahead-market, which are more direct approaches to promoting the availability of physical capacity when it is needed compared with introducing a physical obligation into the financially-based contracts market.

**Physical ownership of assets**

Several retailers in the NEM also own generation assets, i.e. they are vertically integrated to some extent. The corporate structure and policies of a vertically-integrated organisation may be such that the retail arm
contracts with the generation arm, in which case the contracts could be reported as contracts with a specified generation source.

Where the corporate structure does not allow for this, the organisation’s retail arm would be able to report, and count towards compliance, the capacity from the organisation’s generation arm that remain after deducting the capacity from the relevant plant(s) that were sold under contract to other parties. This would be consistent with the proposed treatment of vertically integrated businesses under the emissions requirement.

As noted above, the treatment of vertically integrated retailers requires further consideration. A retailer contracting with another party for the MW capacity requirement will place a financial contractual obligation and consequent financial incentive on the other party. These contracts will likely take into account the reliability of the resources that have entered into the contract (e.g. an intermittent generator will only sell a contract that reflects its capacity factor). However, a vertically integrated retailer with generation may utilise its own plant to meet the requirement. But, all of its generation may be counted and so this method may not take into account the “reliability” of this generation.

**Questions for stakeholder consultation**

- What are stakeholder views on the types of contracts that should be considered eligible for the purposes of the requirement?
- Do stakeholders consider eligible contracts should be financial, or have a link to physical capacity?
- What do stakeholders think of the approach to certify financial contracts back to a physical asset?
- To what extent does the design choice about eligible contracts influence different types of retailers, and so market structure?
- What are stakeholder views on the proposed approach of determining the generation source in a vertically integrated business?

### 5.7 Allocating the requirement

When the requirement has been triggered, the forecast reliability gap will form the basis for the required response from retailers, and so needs to be allocated to individual retailers.

#### 5.7.1 What is allocated?

To incentivise retailers to address the gap, the gap could be directly allocated to retailers to provide a clear signal to retailers who have insufficient contracts that they need to procure more and to provide a signal to retailers who have excess contracts or to new entrants seeking to build new capacity that there is an opportunity to sell their excess capacity.

An alternative approach would be to not allocate the gap to retailers, but have AEMO intermediate new contracts via a “book-build” mechanism between retailers who want to procure new capacity and retailers / new entrants who want to sell new capacity. This is explained in Box 5.3 below.

**Box 5.3 Book-build option**

Following the identification of the gap by AEMO, retailers will have the chance to remedy the gap before the trigger takes effect. Once the trigger takes effect (say 3 years prior to the identified gap), AEMO will conduct a book-build with retailers and new entrants who wish to invest in new capacity and sell new contracts offering into the book-build and retailers and customers who want to buy new capacity bidding into the book build. AEMO will clear the market and allocate contracts to the successful buyers and sellers, with the sellers committing to deliver the new capacity by the required date. New contracts will have a duration that reflects the type of gap identified with a 5 year gap leading to a book-build for new 5 year contracts, which would underpin the new investment.

If the book-build is only partially successful, AEMO will have the option to run the process again nearer the time or to initiate a central procurement of the residual exposure taking into account the size of the gap; prospects of success and urgency of new resources. In any case, if the gap is unfilled with 1 year to go then AEMO would procure the resources along the line of the step 7 below.
The costs of central procurement by AEMO would be allocated to retailers on an ex post basis in the same way that RERT costs are currently passed to retailers. However, lower costs would apply to retailers who helped to solve the gap by participating in the book-build process so as to incentivise the market to address the problem and reduce the likelihood of AEMO having to intervene.

5.7.2 Should the requirement be expressed as a total or an increment?

In considering how any gap should be allocated, the first issue is whether the reliability gap will be expressed as a shortfall (e.g. 500 MW) or a total (e.g. 5,000 MW). In applying the requirement to retailers, retailers could be required to meet the requirement by either meeting the total supply needed to avoid the gap from arising (e.g. 4,500 + 500 = 5,000 MW), or just the shortfall amount itself (500 MW).

If a ‘total’ obligation is imposed, this suggests that the whole market would have to be fully contracted (i.e. to 5,000MW in the example above), which may be undesirable as it would change the relationship between the spot and contract markets. However, this would ensure that the total forecast capacity (as forecast by AEMO at step 1 and triggered in step 3) is met. It is not clear what effect this could have on costs: since retailers will be more fully contracted, the spot price is likely to decrease; however, more contracts will be required which may increase prices for contracts in order to facilitate this supply.

Alternatively, if the percentage of peak load assigned to a retailer is based just on the size of the shortfall itself (500 MW in the example above), the increase in peak load for which the retailer will be expected to have contracted is incremental. This will provide more flexibility in how retailers manage their contract positions – while the incremental increase will need to meet with compliant contracts (discussed above) the remainder of their contracting strategy continues to be up to the retailer. However, for the purpose of compliance, this would require determination of a counterfactual in order to work out how many compliant contracts the retailer would ‘normally’ have purchased, and so, how many additional compliant contracts it would need to purchase in order to meet the requirement, which would be difficult. It is likely that in order to show that the contracts are just “additional” the AER would still need to have data on the total level of contracts anyway.

Under either option, the level that retailers are contracted is expected to increase compared to the status quo – it is just under the first option the increase will be greater than under the second. Any increase in the level of contracting should lead to a reduction in volatility in the spot price, which was a key benefit of the Guarantee as flagged in the Energy Security Board’s November 2017 report.

5.7.3 What forecasts should be used for the allocation?

If the compliance is undertaken on an ex ante basis, then estimates of demand need to be used in order to allocate the requirement to retailers. Under an ex ante approach, the gap would be assigned to retailers based on:

- AEMO’s assessment of the retailers’ load at a particular point in time (e.g. could be based on a PoE 10% day from the previous year) or
- a retailer’s forecast of their load position on an expected PoE 10% day over the next period. While this could be subject to gaming, the retailers’ forecasts could be scaled to AEMO’s forecasts to reconcile the numbers.

Clearly there is the potential for the two views of the world to be very different. One key source of difference will be the treatment of forecast customer load. An individual retailer may expect their mass market load to grow or to shrink and they may take different views on the proportion of C&I load coming off contracts that they can expect to retain.

Another source of difference will be the treatment of interconnectors. When AEMO assesses the future supply-demand position it models the expected flows along interconnectors meaning that some of the peak demand is expected to be met from interconnectors. In allocating the total gap to retailers there needs to be consideration of the treatment of interconnectors.
If an *ex post* approach is used, the above issue is avoided, since actual data for the relevant compliance period will be used. This could be challenging if the actual demand falls short of the level that is forecast by AEMO. *Ex ante* vs *ex post* issues are discussed in more detail in section 5.9 below.

### Questions for stakeholder consultation

- What are stakeholder views on the proposed method of allocating the gap to retailers?
- Should the gap be allocated based on AEMO’s forecasts or on the retailers’ own view of their hedge positions?
- How should C&I load be treated?
- How should load met by interconnectors be treated?

#### 5.7.4 Who is required to respond?

To date, the Energy Security Board has contemplated the reliability requirement would, like the emissions requirement, apply to retailers, as well as each large energy user registered as a Customer under the Rules. There are more than 50 market customers currently in the NEM but only a handful of very large energy users are registered as a Customer under the National Electricity Rules that participate directly in the wholesale market, rather than using a retailer as an intermediary.

While large energy users registered as a Customer are small in number, they account for a sizeable proportion of energy supplied in the NEM. Therefore, the efficacy of the reliability requirement could be materially affected if these large users are exempt from compliance. Further, an exemption could provide a perverse incentive for large users that are currently contracted with a retailer to become market customers. However, a different level of compliance and/or reporting requirement may be justified for those market customers who are not retailers.²²

A further option is to require large energy users that are *not* Customers under the Rules (that is, commercial and industrial customers who use a retailer as an intermediary) to comply with the reliability requirement. The purpose of this approach would be to make sure that large customers that are exposed to wholesale prices via spot pass-through arrangements, or those customers who are on shorter-term or expiring fixed price contracts, still contribute to the reliability of the power system. Large customers switch relatively frequently which would make it harder for retailers to contract under the Guarantee for their load.

As customers on spot price pass throughs bear the risk of spot price volatility themselves, retailers do not have an incentive to contract or maintain physical capacity for this load. Some of the customers do respond to high pool prices by reducing their load so this demand response also needs to be recognised. Similarly, for customers on shorter-term or expiring fixed price contracts, obliging such parties to comply with the reliability requirement would create incentives to contract and support investment in new generation, which would potentially increase competition.

Any process to give effect to this would either need to identify customers on spot pass-through arrangements with retailers; or simply ‘deem’ customers above a certain size to comply with the requirement. Therefore, these businesses would then have similar obligations to retailers to demonstrate the extent to which their hedging strategy promotes a physical response (from themselves or others). If this approach was adopted, these customers would still have the flexibility to transfer this obligation to a retailer via contracts increasing opportunities for smaller retailers to participate in the market.

While the Energy Security Board considers that imposing such an obligation on large customers could have some potential reliability and competition benefits (e.g. increasing the level and tenure of contracts), such an obligation on individual end-users could change the risk profile for large energy users. Without further analysis it is unclear whether this would be positive or negative.

Further, the legal complexity to implement such an arrangement may be more complicated than limiting the obligation to ‘retailers’ (as defined above). There is also the challenge with determining what large customers

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²² As was the case in the discussion of the emissions requirement, the term retailer and market customer are used interchangeably unless noted otherwise.
would qualify (for example, just those that are spot price exposed, or what customers over a particular MW should be subject to the regime). Accordingly, the administrative burden on the AER, retailers and large energy users would need to be proportionate to the benefit.

**Questions for stakeholder consultation**

- Should a different level of compliance and/or reporting requirement be required for large energy users who are registered Customers?
- What are stakeholder views on extending the reliability requirement to large energy users that are *not* market customers?
- If the reliability requirement should be extended to large energy users that are not market customers, what would be an appropriate definition of ‘large energy user’?

### 5.8 Compliance

Retailers will have to submit information to the AER in order for the AER to determine whether or not the retailer has been compliant with the reliability requirement for each region. The compliance framework will provide guidance on the types of information that would need to be reported to the regulator, the form in which that information is to be reported, and the frequency of information reporting.

It will also be important that the compliance framework provide the market with appropriate transparency and confidence that the reliability requirement is being met. Measures to promote transparency include making publicly available de-identified and aggregated information provided by market customers to the regulator as part of their compliance with the NEG, and regular reporting by the regulator on the extent to which market customers are complying with their obligations.

#### 5.8.1 Ex ante vs ex post approach to compliance

The compliance framework can either use an *ex ante* or *ex post* approach, or use a combination of both.

Under an *ex ante* approach, retailers would report to the AER at some time after the trigger point but before the forecast gap is expected to occur. At this time, a retailer would report on the amount of forecast peak load that is covered by the ‘eligible contracts’. Based on this information, the AER would assess whether or not the amount of forecast peak load under contract meets the share of forecast peak load that has been assigned to that retailer as part of any gap.

Once similar assessments are completed for each retailer, the AER would then determine whether or not the gap is expected to still exist. There would need to be some process to reconcile the results from AEMO’s forecasts, and the information provided by retailers. If there is no gap, then no further compliance, or procurer of last resort by AEMO, is necessary. If a gap still exists, retailers who had insufficient eligible contracts to meet their required level of forecast peak load will be in breach of the reliability requirement and so subject to penalties. Given the gap is still forecast to exist AEMO will act as procurer of last resort in order to resolve the gap (see step 7 below).

An issue inherent with an *ex ante* assessment is that it is based on forecasts (by either AEMO or participants) of what is expected to happen. If retailers supply their own forecasts, there is the potential for gaming. However, any differences between retailers’ demand forecasts and AEMO’s demand forecast could be reconciled by scaling retailers’ forecasts to be equal to AEMO’s. The Energy Security Board understands that retailers currently continually adjust their positions up until real-time. An *ex ante* regime could therefore significantly change how retailers manage their contracting positions, but this could assist with earlier and longer-term contracting, which would support investment and so may be of benefit.

Under an *ex post* approach, retailers would report to the AER the amount of peak load that was covered by ‘eligible contracts’ after the gap period had passed. This would allow actual data (e.g. a retailer’s market share during the peak period) as well as the hedging positions that were held to maturity (as opposed to being closed out before realisation) to be used in determining whether the retailer held sufficient contracts to meet its percentage of forecast peak load assigned to it. The challenge with this approach is that assessing reliability after the event may result in a situation where a reliability incident occurs because no retailer invested in new capacity.
This approach relies on retailers managing their risk and making internal assessment about how much of the gap they will be required to meet. It also complicates how penalties are assigned, given any breach of the requirement, that is a gap needing to be addressed, will have been met by AEMO acting as procurer of last resort. Retaining a procurer of last resort function for AEMO in an *ex post* compliance frameworks splits the incentive to close the gap between market participants and AEMO. It also results in a confusion of who is being allocated the risk, and so could result in suboptimal outcomes.

A compliance framework could also have a combination of *ex ante* and *ex post* measures. For example, assume the gap is assigned in aggregate, that is, retailers are required to meet the total supply needed to avoid the gap from arising. Some time period before the forecast gap, for example 12 months in advance, the AER could complete an *ex ante* ‘check in’ to assess whether sufficient eligible contracts are in place to meet the total supply forecast at the time of the gap. The AER would then report to the market whether the gap is likely to be met. If the AER reports that a gap remains, retailers would then be able to adjust their contracting strategies accordingly, in anticipation of the *ex post* investigation as detailed above.

### Questions for stakeholder consultation

- What are stakeholder views on an *ex ante* or *ex post* approach to compliance?
- What are stakeholder views on the implications for the assignment of the gap, given an *ex ante* or *ex post* approach?
- What parameters should be taken into account when deciding between these two options?
- Does an *ex post* or *ex ante* approach impact different retailer types?
- Could an *ex post* approach be effectively implemented while retaining a credible procurer of last resort function?

### 5.9 Procurer of last resort

If retailers do not meet the requirement by the compliance date, AEMO will procure resources to fill any remaining gap.

In the event that the reliability requirement is triggered, perhaps because the response by retailers has been insufficient to address the gap, it will be necessary for AEMO to perform the function of procurer of last resort. This function will give confidence to governments and AEMO that any gap will be resolved so as not to reduce system reliability.

However, the extent of such a function as part of the reliability requirement needs to be carefully considered because it may:

- Split the risk between retailers and AEMO as to who is to address the gap. It will be difficult to penalise retailers for not contracting for capacity, when AEMO is also doing so. This would be more of a concern if compliance was done on an *ex post* basis. Compliance is discussed further in section 5.7.
- Distort market signals to provide the capacity the requirement is seeking to incentivise. A generator will not contract with a retailer to fund investment to provide increased capacity if it could rely upon receiving payment from this procurer process. This distortion in part will depend on the strength of the penalty and is likely to be less of a concern if compliance is being done on an *ex ante* basis.

The extent to which these occur will depend on the timeframe that the procurer of last resort operates in. The longer the period over which compliance occurs, the more distortionary any procurer of last resort function could be. For example, if the requirement is triggered more than 3 years prior to the forecast reliability gap, AEMO could conduct a book build with retailers making both offers to supply new capacity and bids to buy new capacity for a defined period. AEMO would therefore clear the market based on its view about what capacity would be required, and would assign contracts to successful bids/offers and identify any residual gap that may still remain after this process. The outcome of this would be a set of new contracts and a commitment by winning suppliers of capacity to deliver capacity by the required time.

In contrast, if there was a shorter trigger period, AEMO’s response could be similar to the resources procured under the previous long-notice RERT (which allowed for a procurement of last resort up to nine
months ahead of a forecast reliability gap), which is likely to be less distortionary. However, if there is a large and enduring gap to be filled a short trigger period may be inadequate to bring in the new resources and may lead to more limited options and more expensive resources.

Therefore, the Energy Security Board considers that there is a strong interaction between Finkel recommendation 3.4 regarding the need for a strategic reserve and any procurement of last resort mechanism as part of the Guarantee.\textsuperscript{23} The need for, and design of, the strategic reserve is heavily influenced by the preferred design of the reliability requirement of the Guarantee (discussed in section 5.10 below). The Energy Security Board considers that no matter what happens in relation to this issue, there is still an important role for the existing RERT (or a modified version of) in the NEM. This is needed in order for AEMO to manage unexpected shortfalls in demand in an operational timescale.

### Questions for stakeholder consultation

- What are stakeholder views on the including a procurer of last resort function in the reliability requirement?
- When should the last resort function be triggered?
- How should a significant and enduring gap be resolved?

### 5.10 Penalties

The reliability requirement does not lend itself to an explicit graduated compliance framework, as with the emissions requirement. Therefore, non-compliance with the reliability requirement may need to be discouraged through a financial penalty. This could take the form of:

- civil penalties, like those in the existing enforcement regime under the NEL
- a formulaic penalty, such as the volume by which a retailer is short of its reliability requirement, multiplied by either the market price cap or the value of customer reliability
- allocation of costs of centrally procuring resources to meet the gap.

The Energy Security Boards has a preference for allocating (efficient) costs over exacting penalties because penalties are inefficient unless they correct for an externality or market failure. In addition, penalties would be based on forecast amounts, rather than observed costs. It will be important to make sure that in any penalty regime, the AER has sufficient discretion to administer the penalties.

One way in which this could be achieved would be to have a two-stage approach to compliance. In the first stage, the AER’s assessment would evaluate whether market customers have contracted to a level consistent with their allocated reliability requirement. This could be a physical or financial contract, subject to the design choices discussed above. The assessment would identify the extent to which retailers have fallen short of the reliability requirement for the purposes of allocating costs on a relatively formulaic basis. Procurer of last resort costs committed to at the time of the trigger could be allocated in proportion with these shortfalls.

In the second stage, the AER would retain its ability to apply its usual suite of enforcement options. These enforcement options would likely only be used for more significant or repeated failures to comply with the reliability requirement.

Without taking account a retailer’s own view of their forecast demand in these assessments, there may be some mismatch between what AEMO is projecting and what the retailer’s load actually is. If this occurs (e.g. a retailer’s actual load is lower than what AEMO has projected), then some retailers may be burdened with compliance costs for a position that is in excess of their actual position. Conversely, other retailers could get a windfall gain (e.g. a retailer’s actual load is higher than what AEMO has projected) from the assignment of

\textsuperscript{23} As noted above, this Finkel recommendation is currently being considered through the AEMC’s Reliability Frameworks Review, with the matter being coordinated by the Energy Security Board.
compliance obligation being lower. If this is a concern, the scheme could be designed such that only those retailers that were "short" get penalised, but those that are "long" do not get rewarded.

Such considerations need to be weighed against potential gaming issues by retailers with the intent of undertaking actions that would relieve them of a compliance obligation rather than underwriting new investment as the requirement is designed to achieve, e.g dropping C&I customers, shifting load between participants (large incumbent retailers have multiple NEM participant identifiers) or entering into contracts that give the appearance of compliance.

Questions for stakeholder consideration:

- Do stakeholders consider that retailers not meeting the requirement should be charged a penalty or allocated costs or a penalty plus costs?
- Are there other enforcement tools that would be appropriate?

5.11 Other considerations

5.11.1 Competitive markets

While issues of market power and competition are currently being considered more broadly, including through the ACCC’s Electricity Supply and Price Inquiry, the Energy Security Board considers that the design of the Guarantee should make sure that it does not unintentionally further entrench market power and create barriers to entry for smaller players.

The Energy Security Board’s November report discussed the state of market concentration in South Australia, and standard market share indicators and generation trends were presented. In addition, the report discussed mechanisms that could be used to address market concentration. However, the Energy Security Board considers that further consideration cannot be given to these issues until the design of the Guarantee is further developed.

Questions for stakeholder consideration:

- What are stakeholder views on how the Guarantee may impact on competitive markets?

5.11.2 Emissions-intensive trade exposed businesses

Emissions-intensive trade exposed (EITE) businesses carry out emissions-intensive processes to produce products that are exposed to trade competition.

To ensure appropriate measures are being taken to encourage generators to make their capacity available to the market, and ensure that appropriate action has been taken to secure electricity supply, it is necessary for the Guarantee to cover all market customers.

EITE businesses contract electricity through a retailer, or directly as a market customer. In order to meet the reliability guarantee it will be necessary to cover this electricity demand, and ensure EITEs have contracts in place to cover their usage, in particular during peak periods. Due to the nature of these activities, EITE businesses typically have long term electricity contracts. Therefore, it is expected this will have a low impact on EITE contracting practices, but provides an incentive for EITEs to accurately contract to meet their demand during peak periods.

For example, if EITEs were exempt and an EITE activity chose to contract with a portfolio of renewable generators, there may not be sufficient dispatchable capacity to meet demand during times when renewable output is low and demand is high. Unless this EITE business had in place demand response or other dispatchable generation contracted, they would not be able to guarantee they had sufficient supply during peak demand.
5.11.3 Inter-regional trading

The Energy Security Board’s initial advice recommended that capacity be tradeable between regions within interconnector constraints. This means that even if the guarantee did not bind in a region, generators would be able to enter into financial contracts to sell their capacity to retailers in another region where the reliability guarantee had been triggered. Each retailer in the region where the reliability guarantee was binding would be subject to constraints on the level of capacity that could be sourced in this manner.

The Energy Security Board notes that participants can hedge inter-regionally in the manner described above currently, but that many participants don’t due to limitations with inter-regional trading. Therefore, to the extent that inter-regional hedges are currently used, such contracts should also be eligible for use to meet a reliability requirement under the Guarantee.

Therefore, inter-regional transfers should be captured in the forecasts undertaken by AEMO that were discussed in step 1 above, just as AEMO would currently take these into account in the MT PASA and ESOO. There would need to be further consideration about how the shares of inter-regional trades would be allocated to retailers.

The treatment of interconnectors will be an important consideration for state governments and retailers. For example, Tasmania has a high proportion of hydro generation, which meets both emissions and reliability objectives. As the reliability guarantee may be unlikely to bind in Tasmania (although, the capacity of the existing interconnector could be constrained), Hydro Tasmania, the state owned generator, will have strong incentives to offer dispatchable capacity contracts to retailers in other jurisdictions.

5.11.4 Jurisdictional considerations

One aspect the Energy Security Board has considered is how the Guarantee would apply in the ACT. While it is its own market in respect of retailing electricity, the ACT sits within the NSW region of the wholesale market. Therefore, the reliability requirement will apply in respect of NSW, and ACT retailers will be required to comply with the requirement if it is triggered for the NSW region.

The Energy Security Board also notes that in Tasmania, there is a Tasmanian Wholesale Contract Regulatory Framework, which sets out the rules surrounding the provision of Tasmanian electricity derivatives by Hydro Tasmania to other electricity market participants. However, Hydro Tasmania can also offer unregulated contracts to counter parties beyond this. Given that under this framework Hydro Tasmania is required to offer to retailers operating in Tasmania a number of contract products that are broadly consistent with the standard products offered in the NEM, the Energy Security Board considers that the reliability requirement will be able to operate in Tasmania as it would in the rest of the NEM.

**Questions for stakeholder consideration:**

- What are stakeholder views on the operation of the reliability requirement in the ACT and Tasmania?
6 Governance of the Guarantee

Stable and effective implementation of the Guarantee will provide certainty for market participants about its operation, and allow for long term investment decisions to be made in the electricity sector.

While the Guarantee could be implemented in various ways, the Energy Security Board considers that the preferred option is for COAG Energy Council agreement with implementation through existing governance arrangements for the NEM. The majority of the Guarantee would be implemented through amendments to the Australian Energy Market Agreement (AEMA), the National Electricity Law (NEL) and the National Electricity Rules (Rules).

Embedding the Guarantee into the broader energy governance framework would allow the mechanism to be fully integrated with the broader energy rules. This would maximise consistency between the reliability and emissions requirements, reducing complexity and compliance costs for market participants.

6.1 Implementation through NEM governance arrangements

Amendments to the NEL, after being agreed by the COAG Energy Council in accordance with the AEMA, would be implemented by South Australia and automatically applied in each of the other jurisdictions.

The necessary changes to the Rules could be made either by the Australian Energy Market Commission (AEMC) or by the South Australian energy minister.

The NEL and Rules would be amended to:
- translate the emissions target and reliability requirement into retailer obligations, and
- establish the compliance and enforcement framework.

After the initial package of Rules changes were made, the AEMC would be the rule-maker in accordance with its current functions. It would be able to accept and assess rule change requests from any entity relating to the Guarantee, following well-understood 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 mechanism is already flexible to changing market dynamics. Certainty that the policy will last, along with a mechanistic and known approach to any updates, would increase the investor confidence and certainty needed in the electricity sector where the assets are long-lived and the planning horizons are lengthy.

6.2 Relevant Commonwealth legislation

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

The Commonwealth Government would set the electricity emissions target as discussed in chapter 4. Some amendments to existing Commonwealth legislation may also be required. These changes would relate primarily to the emissions requirement, including emissions reporting and information gathering powers, and could require technical amendments to the following Commonwealth laws:
- National Greenhouse and Energy Reporting Act 2007
- Renewable Energy (Electricity) Act 2000
- Australian National Registry of Emissions Units Act 2011
- Clean Energy Regulator Act 2011
### 6.3 Summary of key steps and issues

An outline of the key steps and considerations involved in implementing this approach is provided below.

<table>
<thead>
<tr>
<th>Topic</th>
<th>Approach</th>
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</table>
| **Policy position and intergovernmental agreements** | Commonwealth policy position to set out how the emissions target will be implemented through the retailer emissions requirement in the NEM jurisdictions.  
  AEMA to be amended to reflect:  
  - the inclusion of the retailer emissions requirement; and  
  - additional roles for the AEMC in rule making and the AER in enforcement and compliance (to the extent specific additional roles are necessary).  
  Jurisdictions to agree to changes to the NEL to implement the Guarantee.  
  Consideration will need to be given to a number of matters, including:  
  - AEMC obligation to have regard to national energy objectives and objectives for the Guarantee  
  - use and disclosure of confidential information. |
| **Instrument establishing the electricity emissions target** | The Commonwealth Government will set the electricity emissions target. |
| **Changes to associated legislation (Cth)** | Changes to existing Commonwealth laws and regulations may be required, as outlined above, in relation to emissions reporting and other issues associated with the emissions requirement. |
| **Legislation – implementation of scheme for the NEM jurisdictions** | Amendments to the NEL to be legislated by South Australia and applied in each of the other NEM jurisdictions.  
  The new provisions of the NEL would include key implementation features of the Guarantee, including:  
  - Key obligations on participants, referencing the Commonwealth legislation  
  - Conferral of additional functions (to extent required) on agencies and institutions that will have enforcement and rule-making roles, being the AER and AEMC with respect to the Guarantee  
  - Governance arrangements including:  
    - review processes  
    - powers of agencies with respect to information gathering and confidential information, dispute resolution  
    - penalties, enforcement and appeal mechanisms  
    - reporting requirements. |
| **Commencement – initial rules** | Initial rules to be made by the SA Minister on advice of the AEMC, or by the AEMC. |
## A Abbreviations and defined terms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>ACCC</td>
<td>Australian Competition and Consumer Commission</td>
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<tr>
<td>ACT</td>
<td>Australian Capital Territory</td>
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<tr>
<td>ACCU</td>
<td>Australian Carbon Credit Unit</td>
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<tr>
<td>AEMA</td>
<td>Australian Energy Market Agreement</td>
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<tr>
<td>AEMC or Commission</td>
<td>Australian Energy Market Commission</td>
</tr>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
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<tr>
<td>AER</td>
<td>Australian Energy Regulator</td>
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<tr>
<td>ANREU</td>
<td>Australian National Registry of Emission Units</td>
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<tr>
<td>ARENA</td>
<td>Australian Renewable Energy Agency</td>
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<tr>
<td>ASX</td>
<td>Australian Stock Exchange</td>
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<td>CEFC</td>
<td>Clean Energy Finance Corporation</td>
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<tr>
<td>CER</td>
<td>Clean Energy Regulator</td>
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<td>COAG</td>
<td>Council of Australian Governments</td>
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<tr>
<td>EITE</td>
<td>Emissions-intensive trade-exposed</td>
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<td>ERF</td>
<td>Emissions reduction fund of the Commonwealth Government</td>
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<td>ESB</td>
<td>Energy Security Board</td>
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<tr>
<td>ESCOSA</td>
<td>Essential Services Commission of South Australia</td>
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<tr>
<td>FCAS</td>
<td>Frequency Control Ancillary Services</td>
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<td>GRO</td>
<td>Generator reliability obligation</td>
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<tr>
<td>Guarantee</td>
<td>National energy guarantee</td>
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<tr>
<td>LGC</td>
<td>Large-scale Generation Certificate under the RET</td>
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<tr>
<td>LRMC</td>
<td>Long-run marginal cost</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour</td>
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<tr>
<td>NEL</td>
<td>National Electricity Law</td>
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<td>NEM</td>
<td>National Electricity Market</td>
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<tr>
<td>NEO</td>
<td>National Electricity Objective</td>
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<tr>
<td>NGERS</td>
<td>National Greenhouse and Energy Reporting Scheme</td>
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<tr>
<td>OTC</td>
<td>Over the counter</td>
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<tr>
<td>PPA</td>
<td>Power purchasing agreement</td>
</tr>
<tr>
<td>RET</td>
<td>National large-scale renewable energy target currently in place under the <em>Renewable Energy (Electricity) Act 2000</em> (Cth)</td>
</tr>
<tr>
<td>Rules</td>
<td>National Electricity Rules</td>
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<tr>
<td>SRMC</td>
<td>Short-run marginal cost</td>
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<tr>
<td>tCO₂-e</td>
<td>Metric tonnes of carbon dioxide equivalent</td>
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<tr>
<td>TNSP</td>
<td>Transmission Network Service Provider</td>
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B Interaction between the Guarantee and existing reliability and security work program

Currently, in the NEM, reliability means having an adequate amount of capacity (both generation and demand response) to meet consumer needs. This involves longer-term considerations such as having the right amount of investment, as well as shorter-term considerations such as making appropriate operational decisions, to make sure an adequate supply is available at a particular point in time to meet demand. To deliver a reliable supply, the level of supply needs to include a buffer, known as reserves, so that supply is greater than expected demand. This allows demand and supply to balance, even in the face of unexpected changes. Reliability is different to security, as explained in chapter 1.

As noted in chapter 2, as well as in its *Health of the NEM* report, the Energy Security Board considers that the health of the current reliability of supply in the NEM is CRITICAL, especially in some regions. This rating is partly because of a lack of integration between energy and emissions policies, which has meant that mechanisms to achieve emissions reduction objectives have failed to consider the requirements for dispatchable power. Mechanisms like the RET have resulted in a higher penetration of non-dispatchable renewables, a trend expected to accelerate going forward in order to achieve the 2020 target. As discussed in Chapter 2, one of the RET’s impacts has been the retirement of existing dispatchable plant. More plant retirements are projected to occur in the decades ahead due to both the age of plants and the impact of the RET. Unless addressed, the resulting decrease in dispatchable capacity could adversely affect system reliability.

The reliability risk in the investment timeframe stems from the changing characteristics of the generation mix that are occurring during the transition from:

- thermal generation to a higher share of renewable generation
- large-scale synchronous generation to a higher share of non-synchronous, intermittent generation, that has smaller unit size and is more distributed than before
- centrally scheduled generation to a higher share of distributed, self-scheduled generation.

In relation to reliability, appendix B sets out trends in the generation mix for each region in the NEM, which are driven by the changes set out above. It can be seen from this analysis that the supply-demand balance has been tightening over recent years, most notably in Victoria and South Australia. The reliability requirement will make sure that as this transition to a lower emissions electricity sector occurs, reliability is not compromised and there is adequate dispatchable capacity. In other words, it should help smooth out the reliability bumps that might be caused by the retirement of older power stations.

However, in addition to this aspect, there are also a number of other related reliability and security concerns that are also important, but relate to operational timeframes. For example, the Energy Security Board’s Health of the NEM report noted that system security health is CRITICAL. Managing system security is becoming challenging, particularly in some regions. The risk that essential requirements for security are not present is increasing, along with the market interventions required by AEMO. While the Guarantee will not directly address these other concerns (although it may in part by driving more dispatchable capacity in the NEM), the Energy Security Board still considers these matters important, and that they should be addressed.

Specifically, the Energy Security Board considers that, in addition to the Guarantee, the consideration of strategic reserves, day-ahead markets and demand response are priority issues. The Energy Security Board is coordinating progression of these matters, with the market bodies. These issues interact with the design of the Guarantee, most notably, the issue of strategic reserves. The Energy Security Board will coordinate consideration of these issues, and manage the interactions between the various market reforms occurring.

The below table maps the issues that will not be directly addressed by the Guarantee, the interaction with the Guarantee, and the processes by which these are currently being addressed. The Guarantee is just one part of a multiple pronged approach to meeting the future reliability and security needs of the power system. A progress status update of the Finkel recommendations as at December 2017 was included in the Energy Security Board’s Health of the NEM report.
<table>
<thead>
<tr>
<th>Issue</th>
<th>Current or future work underway</th>
<th>Interaction with the Guarantee</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unexpected retirement of existing plant leading to insufficient capacity available to meet demand</td>
<td>Finkel recommendation 3.2: new requirement for all large generators to provide at least three years’ notice prior to closure. Drafting of the rule change request is underway and consultation to begin shortly. The AEMC will progress this rule change request alongside its <em>Reliability Frameworks Review</em>.</td>
<td>The Guarantee should identify any “gap” in capacity that results from retirement of existing plant and create appropriate incentives on participants to resolve this gap. The rule relating to 3 year notice of closure is intended to provide better information to the market about likely generation closures, with this information being incorporated into AEMO’s forecasting for the Guarantee.</td>
</tr>
</tbody>
</table>
| Higher supply/demand forecasting uncertainty due to supply being increasingly weather dependent, a lack of visibility of DER and demand response, and a more price responsive demand-side | Finkel recommendations:  
- 2.5 – AEMC to review regulatory framework for how DER can help system security. AEMC should propose draft rule changes that incentivise DER participation in frequency and voltage control. Work is underway through the AEMC’s *Frequency Control Frameworks Review*. AEMO is also working with DNSPs to explore operational frameworks for managing system security and reliability in the presence of high levels of DER. The market bodies will liaise with the Energy Security Board to coordinate this.  
- 2.6 – the COAG Energy Council should develop a data collection framework for all forms of DER at a suitable level of aggregation. Register of distributed energy rule change was submitted to the AEMC in late 2017, and consultation will shortly commence. AEMO is also working with DNSPs to establish a data collection framework.  
- 2.11 – the COAG Energy Council should develop a strategy to improve the integrity of energy infrastructure and the accuracy of supply and demand forecasting (extreme weather). AEMO has been working closely with the Bureau of Meteorology to improve forecasting, has implemented enhancements to forecasting models and had a detailed independent audit of short-term forecasting processes undertaken.  
- 6.7 – AEMC should review and recommend a mechanism that facilitates demand response in the wholesale energy market. Consideration of this is underway through the AEMC’s *Reliability Frameworks Review*. The market bodies will liaise with the Energy Security Board to coordinate this.  
- 6.9 – AEMC should review the regulation of individual power | No direct interaction with the Guarantee, other than any improvements to forecasting that are adopted should be incorporated into any forecasts produced for the Guarantee. |
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<th>Issue</th>
<th>Current or future work underway</th>
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<td>systems and microgrids including draft a proposed rule change. The AEMC published a final determination on the alternatives to grid supply rule change request in December 2017. The COAG Energy Council is also investigating the use of stand-alone power systems through its energy market transformation program. In addition, the AEMC is considering forecasting in the NEM more holistically in its Reliability Frameworks Review.</td>
<td>No direct interaction with the Guarantee.</td>
</tr>
<tr>
<td>Stand-alone battery and storage facilities, as well as co-located hybrid sites are emerging. Visibility needs to be addressed along with scheduled vs semi-scheduled status.</td>
<td>AEMO is undertaking a workstream on new resource registration and connections (essentially a review of the registration categories in Chapter 2 of the Rules) AEMC is considering such issues through its Coordination of generation and transmission investment review. In addition, it is also considering issues of visibility through forecasting through its Reliability Frameworks Review.</td>
<td>No direct interaction with the Guarantee.</td>
</tr>
<tr>
<td>High wind / low demand can lead to low price outcomes, with thermal plant coming off line, negatively impacting system strength.</td>
<td>The AEMC’s frameworks for inertia and system strength commence on 1 July 2018 and place an obligation on TNSPs to make minimum levels of both of these services available from 1 July 2019. In addition, in relation to system strength, AEMO has declared an NCAS gap in South Australia, which, under the transitional arrangements in the Rules will bring forward the timeframe for the TNSP to meet the obligation under the AEMC’s frameworks. The AEMC is currently considering a rule change request regarding revised generator performance standards. The rule change request is seeking to introduce a performance standard in relation to system strength.</td>
<td>No direct interaction with the Guarantee. To the extent that minimum levels of inertia and system strength are procured from dispatchable resources, this could impact AEMO’s assessment of any future ‘gap’ in capacity.</td>
</tr>
<tr>
<td>Synchronous generating units are an important source of dynamic voltage support. The displacement of synchronous generation could result in local control issues, placing pressure on existing arrangements. New sources of dynamic voltage control, including from distributed energy resources may be required.</td>
<td>AEMO has committed to further scoping the issues associated with the adequacy of current voltage control arrangements. When this is further advanced, the AEMC has committed to undertake a review of the market and regulatory implications of this through its system security work program.</td>
<td>No direct interaction with the Guarantee.</td>
</tr>
<tr>
<td>Issue</td>
<td>Current or future work underway</td>
<td>Interaction with the Guarantee</td>
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| The system operator requires more flexibility and potentially more reserves to be able to respond to rapidly changing system requirements. Related to this, optimising of efficient outcomes may require taking a longer view of the dispatch horizon. | AEMC has made a rule to implement five minute settlement in 2021, which will more accurately reward those who can deliver supply or demand side responses when they are needed by the power system.  
The suitability of day-ahead markets to the NEM is being considered through the AEMC’s Reliability Frameworks Review. Finkel recommendation 3.4 requires both the AEMC and AEMO to assess the suitability of a day-ahead market. The Energy Security Board will coordinate the market bodies’ consideration of these issues.  
The need for strategic reserves in the NEM is also being considered through the AEMC’s Reliability Frameworks Review. Finkel recommendation 3.4 requires both the AEMC and AEMO to assess the need for a strategic reserve or other enhancements to the RERT. The Energy Security Board will coordinate the market bodies’ consideration of these issues. | No direct interaction with the Guarantee.  
No direct interaction with the Guarantee.  
The need for, design of, and level of, strategic reserves is influenced by the design of the Guarantee. This is discussed further below. |
C Contracting

C.1 Types of contracts in the NEM

Entering contracts enables participants to effectively convert uncertain future spot market prices into more certain wholesale prices to better match upstream or downstream obligations that are also relatively stable across time. Contracting can also be a more cost-effective way to manage risks than vertical integration (see Box C.1).

Box C.1 Contracting as an alternative to vertical integration

Contracting is a way of allowing retailers without generation assets to manage wholesale price and volume risks without resorting to vertical integration. Traditionally, generators and retailers, as an alternative to contracting, have formally merged. Therefore, if the contract market breaks down, or generators and retailers are otherwise unable to contract with each other, they are likely to formally merge, as a way to manage risk.

While vertical integration is not of itself a cause for concern, a market where merger is the only viable way in which participants can manage risk, would have high barriers to entry. A new independent generator or retailer, would become unviable without the acquisition of corresponding retailers or generators.

In the long run, high barriers to entry would reduce competition in both generation and retail markets and lead to higher prices for consumers.

By helping to smooth their future effective wholesale revenues or payments, contracts lower participants’ risk profiles and enable them to obtain equity and debt financing from suppliers of capital (see below). Generators face upstream obligations in the form of fixed costs and variable costs (costs that increase with their power output). The absolute and relative magnitudes of these costs vary considerably by plant technology, fuel type and location. However, these costs rarely vary on a half-hourly basis and are therefore more stable than the spot price.

Meanwhile, retailers typically enter contracts to supply electricity to customers at prices that are fixed or vary in a pre-determined manner over a specified period of time. These often provide fixed pricing over a period of several years.

Box C.2 provides details on the three broad types of contracts used in the NEM.

Box C.2 The types of hedge contracts available in the NEM

Generators use hedging contracts to mitigate their revenue risk, pay for their capacity and finance their businesses. Revenue risk can be disaggregated into price risk (the chance of unexpectedly high or low prices), and volume risk (the chance of actual output differing from what is expected). There are three broad types of hedging contracts offered by generators and purchased by retailers:

1. Fixed-output hedges: these relate to a pre-specified quantity of electricity (in number of MW). The most common forms of contracts are swaps and caps. These types of contracts are explained in section C.1.1.

2. Load-following hedges: in these contracts, the quantity of energy is not pre-specified. Instead, the amount of energy that is settled under the hedging contract depends on (or ‘follows’) the load of the buyer of the hedge contract. Any risk associated with uncertain demand, such as the reduction in demand due to a customer’s increased reliance on their rooftop solar system, is transferred from the retailer to the generator. This type of contract is important for sustaining retail competition, as it mitigates the risks faced by a retailer in managing loads that are of an uncertain size. Most small consumers (residential and commercial) sign this type of contract with their retailer.

3. Generation-following hedges: these contracts also do not pre-specify the quantity of energy under contract. Instead, the amount of energy that is settled under the contract depends on (or ‘follows’) the output of the seller of the contract. Any risk associated with uncertain output is transferred from the generator to the retailer. The predominant type of generation-following hedge is a power-purchase agreement (PPA).

Note that other risk management tools (eg vertical integration and demand management) are also available to participants.

Vertical integration refers to the combination in one firm of two or more stages of production normally operated by separate firms. In the NEM, it refers to the merger of generators and retailers.

For example, coal-fired plant generally have higher fixed costs and lower variable costs than gas-fired plant. Most renewable plant technologies – such as wind and solar – have significant up-front fixed costs, but very low variable costs.

This is sourced from Box 3.1 in AEMC, Strategic priorities for the Australian energy sector, Discussion Paper, 12 September 2017.
The first two types of hedging contracts are ‘firm’, in the sense that the amount of generation output is either available when specified (fixed-output) or when needed by a customer (load-following).

All three types of hedge contracts mitigate generators’ wholesale spot price risk by fixing the electricity price. However, each type of hedging contract provides differing degrees of volume risk mitigation, and therefore revenue risk mitigation. A generation-following hedge provides the greatest revenue risk mitigation to a generator, as this type of hedging contract matches the generator’s actual output. In contrast, conventional generators like coal, gas and hydro are able to offer firm contracts as their output is more controllable than that of an intermittent generator. Therefore, conventional generators face less risk in offering a firm contract than an intermittent generator.

Hedging contracts are of most value to retailers, as these types of contracts underwrite the contracts offered to many of their customers. However, as noted in chapter 2, the effect of the RET has been to tighten the demand/supply balance of these contracts, and so accordingly prices have increased.

C.1.1 Types of firm hedging contracts

Contracts in the NEM are currently traded on the ASX (“exchange-traded”) or traded bilaterally (“over the counter” or “OTC”). The two core contract types are “swaps” and “caps”:

- **Swap:** A swap contract trades a given volume of energy during a fixed period for a fixed price (the strike price). The variable wholesale market spot price is, in effect, swapped for the fixed strike price. The contract is settled through payment between the counterparties based on the difference between the spot price and the strike price. – see Figure X(a). Swaps typically cover a fixed volume of energy for a certain period of time. Swap strike prices reflect the sum of expected future spot prices over the relevant contract period and a contract premium, which may in principle be either positive or negative. However, swap premia are thought to be approximately $2-3/MWh in sellers’ (generators’) favour.

- **Cap:** A cap contract trades a fixed volume of energy for a fixed price when the spot price exceeds a specified price. It provides electricity purchasers with insurance against high prices. The standard contract traded in the market is a “$300 cap”. This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period (Figure B.1). As a result of the one-sided payment obligations arising under a cap, caps are normally sold for a positive up-front premium. The premium for cap contracts in 2018 range from $3.58 to $40/MWh.

![Swap and cap contracts](Figure C.1)

28 A third type of firm contract is a ‘floor’, which provides the contract buyer with the option to sell the notional electricity under the contract at the strike price. A floor is exercised when the spot price falls below the strike price, and is used by market customers to hedge exposures to negative spot prices.

29 However, some parties enter load-following swaps on an OTC basis.

30 As expected future spot prices are unobservable, the sign and magnitude of contract premia are also unobservable.
C.2 Signalling the need for investment and retirement

Potential investors judge the viability of new investments in generation capacity by estimating future spot prices and the revenue that they can potentially generate from their investment.

Contract prices provide information about expected future spot prices, which in turn reflect participants’ views of future wholesale market demand and supply conditions. As expected future spot prices are not directly observable in the NEM participants tend to look to:

- Forward-dated swap contract strike prices – to provide an indication of market expectations of future average spot prices and
- Forward-dated cap contract premia – to provide an indication of market expectations of the future magnitude and duration of spot prices in excess of the cap strike price (typically, $300/MWh).

Taken together, these sets of prices help inform existing and prospective generation investors about what are likely to be profitable and unprofitable decisions. In a (workably) competitive\(^{31}\) wholesale market, decisions that are profitable should promote economic efficiency and the long-term interest of consumers.

If spot prices are expected to be elevated for a large proportion of the year, such that swap strike prices are relatively high, this provides a signal that new baseload capacity is likely to be profitable and efficient. This is because baseload generators have a cost structure (relatively high fixed costs and low variable costs) that make them profitable to run over a large proportion of the year.

Alternatively, if spot prices are expected to be very high for only a small proportion of the year due to extremely ‘peaky’ summer demand relating to say air-conditioning use, such that swap strike prices are fairly flat but cap premia are high, this provides a signal that new peaking capacity (rather than baseload capacity) is likely to be profitable. This is because peaking generators have a cost structure (relatively low fixed costs and high variable costs) that make them profitable to run for short periods of the year.

For example, open cycle gas turbines (OCGT), are ideally suited to sell caps.\(^{32}\) This is driven by their fast-start ability, and their ability to ramp generation up or down between five minute periods. Importantly, their generation capacity can provide energy on demand to capitalise on short-term price spikes.

The role of contracts in supporting investment is particularly important when conditions in the market are changing rapidly or otherwise more uncertain than usual. Observed or expected spot prices cannot translate into new capacity without some degree of confidence that these prices will be sustained long enough for investors to recoup the value of their investment. Contracting can provide this confidence by (for example) enabling investors in new generation capacity to ‘lock in’ a particular price for their generation. Furthermore, contract prices also signal the type and features of generation capacity needed in the market, and incentivise investment in the type of generation that is of the highest value to the system.

C.3 Financing and underwriting new generation

A competitive wholesale market promotes efficient investment and retirement decisions regarding the quantity, technology, timing and location of generation.\(^{33}\) However, the spot market in itself is unlikely to promote efficient investment even if expected future spot prices were directly observable.

Investors are often unwilling to provide finance to a generator at all unless the generator has hedged its anticipated spot market exposure to at least a minimum extent. Hedging provides a means by which generators can reduce their exposures to volatile spot prices and thereby reduce the risk that their plant will face significantly positive or negative profits in any given year. This, in turn, makes investors willing to provide funds to underwrite investment. This reflects the risk aversion of providers of debt and equity capital.\(^{34}\)

\(^{31}\) A workably competitive market is one in which prices tend to efficient costs over time, quality of service matches consumer expectations and choice of products and services is consistent with consumers’ preferences.

\(^{32}\) Hydro-electric generators with water storage are also well-suited to offering caps because they have the capability to start-up quickly and their finite storage implies that notwithstanding their low out-of-pocket operating costs, their variable cost of generation is relatively high – because it reflects the foregone opportunity to generate at the next highest-price time.

\(^{33}\) In theory, in the long run, the entry and exit of generators from the market should ensure that the price of electricity will be sufficiently high to cover not just the operating cost, but the capital cost of building and financing efficient generation capacity.

\(^{34}\) If generation investors and their financiers were risk-neutral, they could be willing to underwrite generation investment decisions purely on the basis of expected spot market revenues.
As a result, the level of contracting that generators undertake reflects their desired capital structure and level of gearing. Generators often enter into contracts of a length and quantity to provide revenue that matches their debt obligations.

In the absence of access to hedge contracts, generators manage their risk by entering into ‘natural’ or physical hedges via vertical integration. The need for extensive vertical integration can itself become a barrier to entry in generation and retail markets. This in turn threatens the competitiveness of the both markets and results in the long run, in higher prices for consumers. Similar considerations with regards to hedging therefore apply to actual and prospective retailers.

Trading in contracts acts as the NEM’s form of capacity mechanism as a result of the information about future market conditions contained in contract prices and the importance of hedging to capital providers. The main differences between the contract market and other capacity mechanisms are:

• participation in the contract market is voluntary
• it is not run or regulated by a centralised decision-making authority
• generators, rather than centralised authorities, determine the level of generation capacity in the market and face financial incentives to avoid overbuilding or underbuilding generation capacity correspondingly.

In the wholesale market, operational and investment decisions are decentralised away from governments and regulators to commercial parties. Generation businesses may be no better at forecasting the future than governments; however, the important difference is that equity and debt holders bear the cost of overinvestment, rather than consumers or taxpayers.

This is a very different way of allocating risk and one which provides very different incentives for efficiency. It is also likely to be in the long-term interests of consumers because generation investors and their counterparties are likely to be better informed, better incentivised and better able to assess and manage these risks than centralised authorities.
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