Designing a more reliable National Electricity Market

Tony Wood, David Blowers and Kate Griffiths

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This Working Paper was written by Tony Wood, Grattan Institute Energy Program Director, David Blowers, Energy Fellow and Kate Griffiths, Senior Associate.

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Overview

Australia's Energy Security Board (ESB) has proposed a 'reliability mechanism' to complement the existing National Electricity Market (NEM). It would work alongside an 'emissions reduction mechanism' as part of the proposed National Energy Guarantee (NEG). This Working Paper describes how such a reliability mechanism might be designed.

The need for a reliability mechanism arises from concern that scarcity pricing in an energy-only market may not deliver adequate investment to meet future demand. This concern increases with more intermittent energy. Wind and solar have high capital costs but effectively zero marginal costs; once the facility is built, the energy produced is free. The resulting highly volatile spot prices become politically and financially unacceptable, making it less likely that new investment in generation will occur.

Appropriate contracting may occur organically, or can be encouraged through a reliability mechanism. Any mechanism should complement rather than replace the current spot market. It would not replace the need to deliver ancillary services such as frequency control and inertia for grid stability.

The mechanism should integrate with the existing market to ensure electricity is available when needed, by encouraging appropriate generation and demand-response capacity and availability. Various mechanisms are used around the world. They range from strategic reserves to capacity mechanisms, which themselves could be delivered as auctions run by a central buyer or through a decentralised obligation model.

The reliability mechanism proposed by the ESB is a decentralised obligation model. In advice to the COAG Energy Council in November 2017,[1] the ESB proposed an obligation on retailers to maintain an adequate level of dispatchable electricity. Retailers would contract for such resources to fulfil that obligation. The details are still being developed.

A retailer obligation would create incentives for investment to deliver adequate future capacity, and could integrate with the NEG's emissions obligation as well as the current spot, derivative and ancillary services markets.

A retailer obligation could involve a central agency setting future requirements for market participants and then managing delivery. Or market participants could ensure adequacy and delivery, with big penalities if they fail to do so. The design trade-off is between certainty and cost.

On balance, we support a well-designed retailer obligation utilising commercial market drivers. But there are risks. The next steps must involve comprehensive stakeholder consultation on design details to avoid unintended consequences and address identified risks.

[1] COAG Energy Council (2017)

Table of contents

1 Introduction

1.1 Background

The modern electricity market must deliver security of supply: adequate investment in capacity that is available to meet demand when needed. There is a risk that the NEM, as currently designed to efficiently balance demand with available capacity, will fail to deliver adequate investment in new capacity with the right capabilities. This risk led to the 2017 Finkel Review calling for a strategic reserve, a generator reliability obligation, and consideration of a day-ahead market[2]. Finkel considered but ultimately deferred the question of a capacity market.

The Australian Energy Market Operator (AEMO)'s September 2017 report on dispatchable capability[3] recommended development of a mechanism to retain existing investment and provide incentives for new investment in flexible dispatchable capability. Grattan Institute's 2017 report, *Next Generation: the long-term future of the National Electricity Market*,[4] recommended preliminary work on a retailer obligation to provide capacity, in case the ESB concluded that a capacity mechanism was needed.

The ESB subsequently recommended a reliability mechanism, as one arm of a National Energy Guarantee, be designed in 2018 for implementation in 2019.[5] The second arm, an emissions reduction mechanism, will be an obligation on energy retailers to meet their load requirements at an average emissions level consistent with the sector target set by the Commonwealth Government.

The COAG Energy Council will consider a preliminary design of the Guarantee at its next meeting, in April this year.

This Working Paper accepts that the ESB has identified the need for a capacity mechanism,[6] and provides initial analysis and suggestions on how to design that mechanism and how it might work.

1.2 International experience

This is not a problem unique to Australia. Many international jurisdictions are adjusting or augmenting their electricity markets in response to fears of generation shortages as they make the transition to increasing quantities of intermittent renewable generation.

Options to address the problem include strategic reserves, capacity auctions run by a central agency, and decentralised retailer obligation models. Germany is developing a strategic reserve of around 5 per cent of generation capacity. Several regional markets in the US and the UK have recently introduced capacity auction mechanisms. And France last year adopted a decentralised retailer obligation model. There are little if any data

[2] Finkel et al (2017)
[3] AEMO (2017)
[4] Wood et al (2017)
[5] Energy Security Board (2017)

[6] While it has been described as a reliability mechanism, the Reliability Guarantee proposed by the ESB is a type of capacity mechanism. It will be described as such for the remainder of this paper.

that provide a basis for a comprehensive, analytical comparison or choosing a preferred model.

Criteria that should be used to choose a capacity mechanism include:

- Adequate investment be made in capacity;
- Dispatchability and flexibility to meet demand;
- Total cost;
- Impact on competition in retail and wholesale markets; and
- Complexity.

One reason a single, preferred model has not been adopted is that every energy market has its own history and legal and regulatory structures. Any new policies or mechanisms must be developed and implemented in that context. Australia is no exception.

The primary objective of a capacity mechanism is to ensure there is enough power when it is needed and when the energy-only market (in which generators are paid only for the energy they produce to meet demand) is at risk of not delivering that power. A capacity mechanism should provide incentives for investment in various dispatchable resources, and integrate with the spot market to make those resources available to meet demand. The price of capacity should reveal the value of security of supply, such that the price drops to zero if there is no risk to security.[7]

It's a complex equation: the incentives must operate in a market of varying supply and demand across seasons, days and even hours. Australia will need to develop a mechanism to suit the NEM's specific circumstances, and then be willing to adjust it to make improvements or address flaws as they arise.

The ESB has recommended a retailer obligation model to provide resource adequacy, and the European Commission came to a similar conclusion in a review of 35 capacity mechanisms in eleven Member States.[8] Chapter 2 describes this approach and alternative versions.

The remaining sections of this paper describe alternative models, expand on an ex post retailer obligation model, and identify the key challenges that would need to be met for such a model to be supported.

[7] RTE (2014)

[8] European Commission (2016)

2 A retailer obligation for capacity

The ESB has identified a retailer obligation as the basis for a capacity mechanism in Australia. Under this model, the obligation is placed on electricity retailers to secure enough capacity to meet the requirements of their customers.[9] It will be left to market participants to determine the type of capacity needed, and the specifications of contracts. In that sense, the mechanism extends the already familiar hedge/derivative market that currently operates alongside the spot market, and the Power Purchase Agreement-type contract market that arose under the Renewable Energy Target (RET).

There are two broad forms of retailer obligation: an *ex ante* obligation, where the amount of capacity a retailer needs to have contracted is determined and imposed by a central agency in advance; and an *ex post* obligation, where an assessment of whether a retailer had sufficient capacity is made after the event, with the retailer subject to a penalty if it has failed to meet its obligation.

The key difference is the role of the central agency and the extent to which the mechanism depends more on market dynamics or on central planning.

2.1 Ex ante retailer obligation

In an ex ante model, the market operator forecasts peak demand, and retailers must procure sufficient capacity to meet their share of that expected peak demand, plus a reserve margin, typically 10-to-20 per cent. Under this model, the market operator takes a central role in determining how much – and what kind of – capacity is needed. Retailers must procure enough capacity in advance, or face a penalty. This penalty would at least cover costs incurred by the central agency to meet a shortfall. A form of ex ante capacity obligation was introduced in Western Australia and has been in operation in California for more than a decade (see Box 1).

The primacy of the central agency in this model means greater certainty for policy makers and customers, because requirements for capacity are set (and met) before expected peak demand events.

But the role of the market operator can rapidly become very complex, because it must manage both the long-term investment and the short-term dynamic operation cycles. In California, retailers are required to make annual and monthly reports to demonstrate that they can meet their system, local and flexible requirements.

9 This will include generation, storage or demand-response, where customers are given incentives to reduce their use of electricity at times of extreme demand.

Box 1: The Californian model

Under the Californian Resource Adequacy program, the market operator forecasts peak demand for the coming year, and retailers are obliged to procure sufficient capacity to meet their peak load, plus a 15 per cent reserve margin. Three types of capacity obligation are set: (1) capacity to meet system peak demand; (2) capacity to meet local peak demand; and (3) flexible capacity to manage contingencies.

The program does not itself take a longer-term view of the market's need for dispatchable capacity. Since the early stages of the program, there has been ongoing debate as to whether it should evolve to a centralised capacity market auction program or continue as a bilateral market.[10] To address this issue, the Utilities Commission has a separate program under which it authorises utilities to procure new generation resources to meet system, local and flexible reliability needs. This Long-Term Procurement Plan (LTPP)[11] works on a ten-year time horizon that is currently through to 2024. The utilities' procurement plans must give priority to energy efficiency and demand-response, ahead of renewable generation and then clean-fossil generation.

The costs of the resources secured under the LTPP can be passed through via the utilities' transmission charges. These arrangements involve high levels of complexity and regulation.

The market operator is also responsible for the accuracy of the peak demand forecast. This means that the operator may need to establish its own facilities to cover the risk that the retailers meet their obligations, but the operator got the demand forecast wrong. One way to do this is to establish a strategic reserve. To avoid the need for a strategic reserve, the market operator can set a higher reserve margin for retailers. This may avoid the possibility of generation shortages, but it may also mean more generation is procured than needed, leading to higher costs for consumers.

2.2 Ex post retailer obligation

In the ex post model, retailers are obliged to purchase capacity, either through contracts or capacity certificates, to cover their demand. Total system need is calculated on actual peak demand (assessed after the fact) rather than a capacity volume target. A form of ex post capacity obligation was adopted in France last year, after peak demand grew much more quickly than average demand, and medium-term forecasts suggested possible shortages.

The ex post model places the obligation to meet demand on electricity retailers, but does so in a way that is more market-focused than other models.[12] The market operator publishes estimated capacity requirements every year in the lead-up to delivery – much like AEMO's annual Electricity Statement of Opportunities – but the key measure is the level of demand during peak periods in the delivery year. Retailers determine how they will cover their obligation, and the market operator verifies the outcome after the event.

[10] Chaterjee and Oren (2007)
[11] CPUC (2018)
[12] CIGRE Working Group (2016) p78

The obligation would be triggered at nominated periods when there was, or was expected to be, high stress on the system (the equivalent of the Lack of Reserve conditions that currently operate in the NEM). AEMO would set the number of critical peak days, provide a demand forecast, and nominate a security margin several, maybe five, years ahead. It would also set the shortfall penalty at this time.

AEMO would then update this forecast at least annually until the operating year. In the operating year, critical days would be nominated a day ahead. Retailers would need to continually refine their commercial requirements in the lead up, including the need for a reserve buffer to be sure of avoiding the penalty.

The aggregate obligation to meet demand provides the incentive for investment. This could be delivered by retailer-supplier contracts and/or by establishing and trading capacity certificates.

Retailers are unlikely to be able to precisely predict their demand (but are in a better position than anyone else), so they have an incentive to purchase extra capacity and organise demand-response. Any extra capacity a retailer contributes to the system is paid for at the market value; when they have insufficient capacity they incur a penalty.

If retailers in aggregate have secured enough capacity to meet the total system need, then there is a rebalancing afterwards between those who procured more capacity than they needed and those who procured less. If retailers in aggregate do not secure enough capacity to meet the total system need, then those retailers who over-procured still get paid, but those who under-procured face a heavy penalty, which should be set according to the Value of Lost Load (VOLL). In the French model, the penalty is set at around AUD$90,000 for every megawatt below what was needed.

Critical design challenges for this model are to ensure that the retailer's obligation accurately reflects its contribution to any shortfall risk, and that the compliance and penalty regime is calibrated to provide efficient incentives.

A mid-2016 assessment of the expected impact of the French model concluded that the mechanism should meet the government's reliability standard, whereas the energy-only market would struggle to replace capacity reductions caused by the closure of plants. The assessment found the model could save French consumers €400 million a year, on average, from 2017 to 2030.[13]

[13] FTI (2016)

3 Alternative models

Beyond a retailer obligation, international experience suggests the range of models that could be considered for Australia include:[14]

- Consumer-driven capacity subscription
- Capacity procured via central auction

This Working Paper does not further assess the consumer-driven capacity subscription model because it has not been adopted in any jurisdiction and remains a theoretical proposition.[15]

3.1 Capacity procured via central auction

Capacity auctions are the most direct way to ensure adequate resources. Under this model, a central agency such as AEMO determines future demand, adds a reserve margin, and then runs an auction to contract for delivery of that capacity.[16] The payments under those contracts are passed through to consumers, as with other costs incurred by the central agency.

Capacity auctions can take many different forms, with auctions held for different forms of capacity and over different timeframes. The complexity can escalate rapidly. If initial auctions are held several years in advance to drive investment, secondary auctions may then be needed between the initial auction and the delivery period, as circumstances change, and participants want or need to renegotiate their commitments or exposure.

The capacity auctions model directly addresses the 'missing money' problem of energy-only markets, by providing transparency and clear future price signals.[17] It gives government control over total system capacity, and enables system coordination and long-term planning of capacity and capability needs.

Such a centrally planned approach, like government-backed electricity generation, will shift investment risks and costs onto consumers, but a well-designed capacity auction can minimise the shift.

The capacity auctions model is used in the UK and some US markets such as the 'PJM', a network which covers the eastern states of Pennsylvania, New Jersey and Maryland, with around 65 million consumers and more than 182 gigawatts of installed generating capacity.[18]

In the UK, the main capacity auction clears four years from the delivery date, with a secondary auction about six months from delivery. In December 2016, National Grid, the central agency, announced the results of its auction for delivery in 2020-21. The

[14] CIGRE Working Group (2016); Wood et al (2017)
[15] See Wood et al (2017) p34 for further discussion.
[16] An alternative centrally managed mechanism is a capacity payment, where a central agency sets a price for capacity, and the market effectively determines the volume. See CIGRE Working Group (2016) p40. Another variation to the model is described in Box 2.
[17] ibid Working Group (2016)
[18] Monitoring Analytics (2017)

aggregate capacity was 52 gigawatts, at a clearing price of £22.50 per kilowatt.[19] This auction secured around 4.8 gigawatts of new or refurbished capacity. Such auctions generally secure existing generators and demand-response, rather than new investment. The result of the secondary auction for 2017-18 was announced in February 2017.[20] It secured an additional 2 gigawatts for the lower-than-expected price of £6.95 per kilowatt.

The PJM capacity market in the US was introduced in 2007 to address concerns that the existing market would not create adequate incentives to build new capacity when and where it was needed.[21] Previously, under an ex ante retailer obligation model, retailers were required to have capacity through ownership, contract, or demand-response, equal to their peak load plus a reserve margin. Since 2007, retailers can also meet this requirement with capacity obtained through capacity market auctions. Base residual auctions are held for delivery three years ahead, followed by incremental auctions in each of the three intervening years to allow for trading in changed circumstances.

A criticism of capacity auctions is that, like the ex ante retailer obligation, the responsibility for setting and meeting capacity requirements rests with a central agency, probably the market operator. Unlike the ex ante obligation, however, the market operator also procures the capacity. The risks are over-procurement, and higher cost to consumers.

Box 2: Reliability Options

A variation on capacity mechanisms structures the product as a financial option rather than a physical volume. These Reliability Options are allocated through a centralised auction. The holder of the option receives an annual payment from the system operator, who then has the right to call on energy from the holder at a pre-determined price. Ireland adopted this model after an extensive review of its electricity market called for a capacity mechanism.

Proponents say Reliability Options produce more competitive outcomes.[22] Australia should make a detailed assessment of this alternative, because it is the version of the centralised auction model most closely aligned to the retailer obligation model.

Capacity auctions have been described as *"highly mechanised, centrally administered constructs governed by thousands of pages of complex rules"*.[23] The American Public Power Association estimated that the PJM's capacity market in 2016 added $120 of "unnecessary cost" per year to the average household bill, and $19,000 for an average industrial user.

Figure 1 illustrates wholesale costs in a variety of US markets, with and without capacity markets.

Some capacity auctions have been criticised for failing to consider emissions outcomes. The UK capacity auction has been criticised for delivering high-emissions supply, such as diesel generators.[24]

[19] National Grid (2016)
[20] PEI (2017)
[21] Bowring (2013)
[22] CIGRE (2016) p37
[23] APPA (2017)
[24] Orme (2016)

While solutions have been suggested, including emissions constraints in the auction eligibility criteria,[25] this underlines the need for integrated energy and climate policy. The existence of an emissions guarantee alongside the reliability guarantee should mitigate this problem.

A further criticism of capacity auctions of this sort is that they don't deliver much new investment or demand-response, and mostly provide payments to generators that would have run anyway.[26]

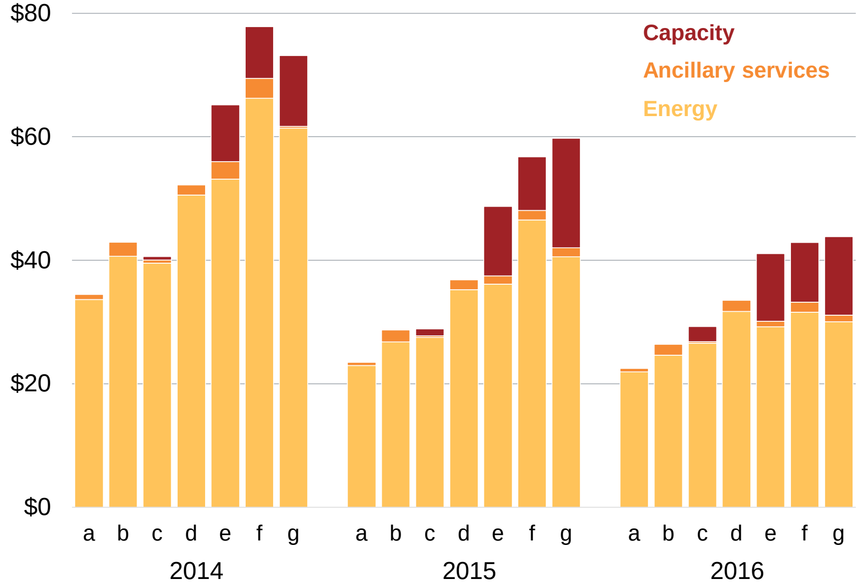
Yet, a capacity auction's core weakness is also one of its strengths. The fact that a central agency has control over the amount of capacity available in the market provides assurances that there will be enough generation to meet electricity needs. Such an assurance may prevent policy makers from more directly intervening in the market.[27]

Because payments come from the central agency and not retailers, an auction will, theoretically, benefit merchant generators that are not vertically integrated. A revenue stream that is independent of retailers will mean that any market power in the retail market will have less of an impact.

The real benefit of this approach depends on whether a centrally determined auction process can procure generation and other capacity at a lower cost than a decentralised market. Reverse auctions have had some success in procuring low-cost renewables, but most markets with capacity auctions have been criticised based on increased costs to consumers.[28]

Figure 1: Electricity costs in US electricity markets with and without capacity markets

Wholesale electricity prices (US$ per megawatt hour)



Notes: Market structure is not the only contributor to cost. Generation types, governance, and historical factors all affect wholesale electricity prices. a = Southwest Power Pool (SPP), b = Texas (ERCOT), c = Midcontinent (MISO) average, d = California (CAISO) which has a capacity obligation on retailers, e = Pennsylvania-New Jersey-Maryland (PJM) average, f = New England (ISO-NE) hub, g = New York (NYISO) average.
Source: Grattan analysis of Potomac Economics (2016) and Potomac Economics (2017).

[25] Norton Rose Fulbright (2015)
[26] Parr (2015)
[27] Wood et al (2017)
[28] Wood et al (2017)

4 Preferred model for Australia: an ex post retailer obligation

The choice of model for Australia is a trade-off between cost and certainty/control. A central agency is likely to be risk averse, potentially overvalue security of supply, and set a high obligation to guarantee reliability. The result would likely be more capacity being available, but at greater cost. By contrast, a decentralised model would likely be cheaper, but politicians and policy makers would have limited influence over how much and what types of capacity is procured.

A centralised model, enforced by a central agency, such as AEMO, requires the central agency to specify multiple levels of reliability and to then be satisfied by the retailers that they can meet those requirements. There also needs to be a method for quantifying the reliability characteristics of different technologies for generation, storage and demand-response. Under an ex post retailer obligation, these issues rest with the market participants rather than the market operator.

Under a decentralised model, the market will look to meet its obligation at least cost. Retailers will determine the optimal amount of capacity (including reserve) – but the market may undervalue security, providing less assurance for politicians and policy makers that sufficient capacity is available.

Market participants can make different choices about how best to meet peak demand, thereby supporting a greater variety of capabilities in the system.

Demand response is likely to be a key source of dispatchable capacity under an ex post model – more so than under either the ex ante or central auction models. Availability of demand response is less certain well in advance, so its value would be reduced under the ex ante and central auction models. Under an ex post model though, demand response offers retailers a relatively cheap, ‘last minute’ option to buffer the risk of being penalised. This is a core strength of the ex post model, given that demand response can be one of the cheapest options.

Retailers would contract with, or purchase capacity certificates from, generators, other capacity providers, and demand-response providers, in the lead-up to the critical peak periods where the obligation kicks in.

As a peak period approaches, retailers can monitor the risk of a significant penalty. If the system is in a state of overcapacity, the price of capacity will likely be low and the risk to the retailer low. But if supply is tight, there is a substantial incentive for retailers to contract for new generation and organise demand response. At times of tight supply, capacity will be more valuable, so this alone might provide sufficient incentive for new generation to enter the market. In this way, an ex post retailer obligation should encourage investment in new generation when supply is tight.

Table 1 compares the ex ante and ex post models of the retailer obligation against the criteria laid out in Chapter 1.

Table 1: Comparison of models

Criteria	Ex ante	Ex post
Resource adequacy	The central agency can ensure resource adequacy through the level of reserve margin it chooses. The higher the reserve margin, the more certainty this model provides to policy makers.	An ex post obligation should deliver adequate resources if the penalty is set at the value of lost load. But the fact that it is left to the market means less certainty for policy makers.
Dispatchability and flexibility	The central agency may specify which kinds of capacity to procure to ensure flexible resources are available. Dispatchability and flexibility rests on the ability of the central agency to accurately predict the resource mix required. The spot market continues to provide the incentive to dispatch.	Retailers determine the right capacity mix for their load profile. The spot market continues to provide an incentive to dispatch, but the ex post model also has an additional incentive to deliver on specified peak days (to avoid penalty).
Cost	The central agency must determine the level of reserve margin. Given imperfect information, this is likely to be conservative and cost more than under an ex post approach. The central agency also determines the mix of generation to meet reliability needs.	Retailers each determine the appropriate reserve margin and the balance of risk and cost for their portfolio. Retailers are likely to choose a lower reserve margin than a central agency and will, therefore, cost less. Demand response is also likely to be a key part of the ex post model, as back-up to ensure retailers avoid penalty. Demand response typically costs less than additional generation.
Retail and wholesale competition	Placing an obligation on retailers is likely to entrench any market power that already exists in the retail and generation markets. There is unlikely to be a difference between ex ante and ex post.	Placing an obligation on retailers is likely to entrench any market power that already exists in the retail and generation markets. There is unlikely to be a difference between ex ante and ex post.
Complexity	A central agency will be required to accurately forecast future demand, and determine the types of generation needed, including for short-term dynamic operation cycles. The agency will also need to monitor capacity procured by retailers, and determine an appropriate penalty.	The complexity for policy makers will be in determining the penalty/value of lost load. Policy makers may also need to ensure a certain level of transparency by monitoring capacity certificates (otherwise the market could become less transparent as retailers and generators enter into more bilateral contracts).

This Working Paper recommends a decentralised obligation model as the first-choice model for the reliability requirement of the National Energy Guarantee. This is a major development for the NEM, and the design detail will be critical to avoid problems and unintended consequences. There will need to be intensive consultation with a wide range of stakeholders. If major flaws remain with this model, then an alternative such as the ex ante model may need to be considered.

4.1 Key design features

An ex post retailer obligation has the advantage in Australia of being similar in effect to a highly contracted energy-only market. While the current energy-only market does not impose an obligation on generators or retailers to meet demand, generators do have an incentive to make their plant available to meet their contracts with retailers (or face financial penalties), and retailers have an incentive to contract with generators for protection against extreme prices.[29] There are, however, some design choices that need to be made if the scheme is to work effectively.

4.1.1 Penalty price

The penalty for failure to meet the reliability obligation needs to be high enough to reflect the real market value of lost load, but not so high as to produce the same high cost and level of risk aversion as a central buyer mechanism. This outcome would negate the key benefit of the ex post model.

Under a retailer obligation, the penalty would be set at the Value of Lost Load (VOLL). VOLL would need to be significantly above the market price cap (currently $14,200/MWh in the NEM).

The compliance regime for the reliability requirement of the Guarantee is inherently more complex than the compliance regime for the emissions reduction requirement, because failure to meet an emissions target on a specific day or even in a specific year can be made up in subsequent periods, whereas failure to meet a reliability requirement clearly cannot.

The way in which the compliance penalty is set, operates and is reviewed is critical to the efficiency of this model, as was found with the shortfall penalty charge under the Renewable Energy Target (RET).

4.1.2 Certificate market

Under a retailer obligation, some form of secondary or trading market in capacity would probably evolve quickly. In a similar way that renewable energy credits are created and traded under the RET, capacity credits could be created and traded under a retailer obligation mechanism. The ESB argues that the existence of contracts will lead to more competitive bidding, which in turn will reduce wholesale prices[30].

Generators could create and sell capacity credits, much like they do cap contracts. If, on the day, a retailer holds the capacity

[29] CIGRE Working Group (2016) p30

[30] Energy Security Board (2017)

credits they need, but the generator is out of action, the penalty falls to the generator.

A transparent, liquid trading market is one way to mitigate the effects of concentration of market power, and the Guarantee should facilitate development of such a market.[31] The Australian scheme should draw on the French scheme, which includes a market in capacity certificates.

4.1.3 Compliance regime

Retailers will be required to demonstrate that they have met their obligation after a peak period has occurred. Even if adequate capacity is available for the peak period, some retailers may under-deliver on their obligation, while others may over-deliver. This raises equity issues. Any process needs to balance cost and complexity against certainty that the obligation is being met.

The creation of a capacity trading scheme will assist the regulator to identify where retailers have met their obligation. Retailers would need to submit their capacity credits or certificates to the regulator to prove that they purchased sufficient capacity for the peak period.

[31] European Commission (2016) p15

5 Other considerations

An effective, detailed design for an ex post retailer obligation should integrate with the spot market and AEMO's operating rules. Neither a strategic reserve nor a generator reliability obligation should be necessary. But policy makers may consider whether the Reliability and Emergency Reserve Trader mechanism and/or a day-ahead market would be required to provide additional security to governments and AEMO.

Market concentration also needs to be considered. An increasing reliance on contracting in the market is likely to reduce transparency and benefit those few companies able to enter into large, long-term contracts. Understanding how to mitigate against increasing market concentration will be critical if the retailer obligation is to put downward pressure on prices.

5.1 A strategic reserve?

Establishing and paying for an amount of generation capacity that is set aside to be used by the market operator in emergencies is the simplest way to complement the energy market. It can be attractive in markets that have sufficient overall capacity but have concerns about availability during infrequent periods of high demand. A strategic reserve provides a temporary solution to potential capacity shortages, pending greater clarity on whether a permanent mechanism such as a capacity market is required.

Finkel recommended that by mid-2018, AEMO and the Australian Energy Market Commission (AEMC) should assess the *"need for a Strategic Reserve to act as a safety net in exceptional circumstances as an enhancement to the existing Reliability and Emergency Reserve Trader mechanism"*.[32] AEMO subsequently argued that a strategic reserve of *"flexible dispatchable energy resource"* was required over the five summers to 2021-22.[33] It succeeded in securing such a reserve for the summer of 2017-18.

Under a retailer obligation there should be no need for a strategic reserve. Either the market operator sets the reserve margin high enough under the ex ante model, or the market delivers sufficient generation under the ex post model. Policy makers may wish for the added safety net of a strategic reserve, but it is likely to increase costs to consumers. And reserves do not solve the problem of inadequate resources.[34] For strategic reserves to work, there must be a clear distinction between 'reserve' generation and normal generation. If the lines are blurred – for example, if market participants believe governments might use reserves regularly rather than only in emergencies – then market participants may build less generation themselves, undermining the end goal.

With strategic reserves, significant generation capacity is sitting idle most of the time, and governments can be tempted to slip it into regular use. To avoid this problem, Australia's Reliability and

[32] Finkel et al (2017)
[33] AEMO (2017)
[34] Wood et al (2017), p33

Emergency Reserve Trader (RERT) operates as a temporary rather than permanent reserve mechanism.

One of the main arguments for a central capacity auction or ex ante obligation, over an ex post obligation, is that they would allow other safety net mechanisms to be triggered if the requirement is not met. If other mechanisms are required, then the penalties and/or reserve margin have not been set appropriately.

Recognising that this is a risk with any new mechanism, there may be a case for keeping the existing RERT as a temporary reserve option. The RERT does not increase costs for consumers unless activated, and should only be activated if needed.

The RERT could exist alongside an ex post retailer obligation. The market operator would monitor capacity certificates in the lead up to determine if retailers have procured sufficient capacity. If it looks unlikely that retailers will meet their obligation, then the RERT could be used. The retailer obligation would still be assessed ex post, as if the RERT had not been used. Any retailer that did not procure sufficient capacity would still have to pay the penalty – and that penalty would be hefty if the RERT was the difference between meeting demand and not.[35] Keeping the RERT might be sufficient to provide the certainty sought by policy makers and politicians, without the cost and complexity of auction or ex ante models.

Box 3: International versions of strategic reserves

The German Government adopted a strategic reserve rather than a capacity market in its transition phase, in part because of concerns that a capacity market would excessively distort the existing market.[36] The decision had its detractors. Some market participants argued that capacity markets would be unavoidable in markets with large shares of renewables with zero marginal cost: *"The energy-only market is an unbeatable instrument to dispatch electricity efficiently and ensure assets are used in the best possible way. It's not a good way to incentivise investment."*[37] The reserve will eventually amount to 5 per cent of the maximum power demand. The German Government insists it will not interfere in the market, even at times of very high prices. It argues that as a consequence, scarcity pricing will deliver investment in flexible power generation, demand-response, and storage.[38] The strategic reserve exists alongside tougher rules for suppliers and traders, designed to ensure they buy enough power at the right time for their customers.

In 2015, the US Federal Energy Regulatory Commission approved a plan for the California Independent System Operator to use a competitive solicitation process to acquire backstop capacity when there are unexpected shortages or grid reliability problems.[39] This mechanism operates alongside the existing Resource Adequacy Program and, like that program, solicits offers annually, monthly and daily for local, system and flexible backstop capacity as the need arises.

35 The penalty could be equivalent to VOLL or could reflect the cost of the RERT.
36 Jenkin et al (2016)
37 Platts (2014)
38 Clean Energy Wire (2016)
39 Platts (2015)

5.2 A day-ahead market

A day-ahead market is a form of forward market in which electricity, or the rights to electricity, are traded ahead of use.[40] A day-ahead market operates alongside the real-time wholesale market. Generators can access revenue from both: electricity is sold in the day-ahead market and in the real-time market.

If generators cannot deliver the electricity they promised in the day-ahead market, they must purchase replacement electricity in the real-time market. This places an additional financial risk on generators, encouraging them to 'guarantee' their bids through back-up capacity or contracts with other generators, and may therefore help to increase reserve capacity in the system.

Many electricity systems in the US and Europe have day-ahead markets.[41] In general, prices in the day-ahead market are higher than those in the real-time market. This is because purchasers are willing to pay a risk premium on electricity in the day-ahead market to avoid price shocks that might occur in the real-time market.

A day-ahead market provides greater transparency on the near-future availability of electricity generation. As a result, a day-ahead market may help improve the short-term reliability of the system. But, as with the energy-only market, a day-ahead market does not eliminate questions about resource adequacy in the long run.

[40] Schubert et al. (2002)
[41] *e.g.* PJM, ERCOT, California, NYISO, ISO-NE, Northeast, Midwest, Nord Pool.

5.3 Mitigating the risk to competition

Market concentration is already an issue in Australia's electricity sector: in South Australia and Queensland the generation market is heavily concentrated; in most regions the retail market is dominated by three integrated generator-retailers; and the renewable energy contract market (through the Renewable Energy Target) is dominated by those same three companies.

As the ESB has acknowledged, there are legitimate concerns that obligations on retailers under the proposed National Energy Guarantee could make things worse for consumers. Even without the Guarantee, any form of emissions reduction or dispatchable capacity model that shifts the balance in the market from spot to contracts could raise the same concerns.

The ACCC and the COAG Energy Council will have to confront the issue of market concentration, and the designers of the Guarantee should specifically analyse the issue. Several approaches should be considered to mitigate this risk:

- In the PJM, the design of its capacity mechanism includes rules that modify competitive behaviour when there is structural market power.[42] Specifically, existing capacity must be offered at a price equal to the marginal cost of capacity, if the offer, in the absence of mitigation, would increase the clearing price.

[42] Bowring (2013)

- Bilateral contracts can reduce price transparency in the market. For example, Australia's domestic gas market is characterised by a lack of transparency in the wholesale market due to its reliance on bilateral contracts. In the electricity market, an increased reliance on contracts is inevitable as more supply comes with zero marginal cost. Therefore, the Guarantee should require publication of the key terms of such contracts.

- A transparent and liquid trading market in capacity certificates would mitigate some of the adverse impacts of market concentration.

- Forced divestiture is a last resort option for managing market concentration, but would be highly controversial and seems to have been ruled out by the ACCC.

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