Pathways to a Sustainable and Resilient NEM

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Definitions

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australia Energy Regulator
CAISO	California Independent System Operator
CEIG	Clean Energy Investors Group
CFD	Contract for Difference
CIS	Capacity Investment Scheme
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DNSPs	Distribution Network Service Providers
ERCOT	Electricity Reliability Council of Texas
ESB	Energy Security Board
EWEC	Emirates Water and Electricity Co.
FID	Final Investment Decision
GO	Guarantee of Origin
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
kWh	Kilowatt-hours
LGCs	Large-Scale Generation Certificates
LRET	Large-Scale Renewable Energy Target
LSEs	Load Serving Entities
LTESA	Long-Term Energy Service Agreements
MWh	Megawatt-hours
MLF	Marginal Loss Factor
NEL	National Electricity Law
NER	National Electricity Rules
NEM	National Electricity Market
NSW	New South Wales
PoLR	Procurer of Last Resort
PPA	Purchase Power Agreement
PV	Photovoltaics
REGO	Renewable Electricity Guarantee of Origin

RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RRO	Retailer Reliability Obligation
SRES	Small-scale Renewable Energy Scheme
SRMC	Short Run Marginal Cost
UAE	United Arab Emirates
VRE	Variable Renewable Energy

Executive summary

This paper is the second in a series developed by Castalia for the Clean Energy Investor Group (CEIG). In our earlier discussion paper, we argued that it is technically possible to transition to a reliable and affordable electricity system substantially built around renewable generation if the market design was changed to overcome two key failings of the current model:

- Lack of a sufficient degree of coordination and control to ensure that all elements of a technologically complex system are aligned (including storage, transmission and firming). The current market design which takes a relatively hands-off approach to such coordination worked well for a power system built around a small range of dispatchable fossil fuel technologies, but is no longer fit for purpose in an increasingly renewables-dominated system where physical security of supply depends on the careful balance between investments in different types of generation, transmission, and storage
- High cost of capital resulting from inefficient risk allocation, which forces consumers to compensate investors for unpredictable cash flows (apart from various taxpayer funded schemes). While some long-term power purchase agreement (PPA) are available, for the most part the market does not provide adequate supply of long-term contracts. While this risk appears to fall on investors, it is consumers who ultimately pay for the high cost of capital.

In other words, the key elements of the reform should be:

- Efficient risk allocation to provide long-term cash flow stability to investors. This will enable investment to be financed at a reasonable cost without relying on taxpayer funding. Efficient risk allocation means that investors face the risks they can control—such as technology, delivery and operating risks—but do not force consumers to compensate them for the broad market risks which are generally outside their control. With long-term predictable cash flows, generation investments would be able to proceed while targeting lower profitability. This will result in lower power bills for customers compared to a market with unpredictable and variable cash flows
- Deliver socially acceptable price outcomes
- Improve coordination of investment to achieve physical security of supply
- Be implementable by the end of the Capacity Investment Scheme (CIS) in 2027.

This paper explores three potential solutions, which build on existing market mechanisms, to deliver the key elements:

- A renewable portfolio standard (RPS) paired with a dispatchable capacity requirement. An RPS requires retailers to hold renewable certificates for a specified target share of the energy served. Such certificates can serve as effective substitutes for long-term contracts. A dispatchable capacity requirement is a relatively blunt but potentially effective tool for ensuring balanced investment across different types of generation and storage capacity for physical security of supply.
- An RPS paired with an ERCOT-style reserve margin. The Electric Reliability Council of Texas (ERCOT) operates an energy-only market similar to Australia's, but with a

considerably more pro-active and thorough regime for ensuring the system can reliably meet demand at all times.

- Coordinated auctions for long-term contracts for the technically efficient mix of renewables, storage, firming and transmission to meet the expected load reliably.

The above options draw on the existing instruments such as LRET and CIS but will require considerable refinement and development to avoid past errors. For example, a RPS should not be simply a restoration of the LRET, while coordinated auctions do not mean continuation of the current CIS. Rather, the objective is to build on the key elements of the existing mechanisms while addressing their challenges.

The options we consider offer different trade-offs between the degree of market flexibility in responding to price incentives compared to certainty and reliability of outcomes. In essence, greater reliance on decisions by a market coordination body—such as Australian Energy Market Operator (AEMO)—combined with measures that give long-term revenue certainty to investors will reduce market risk. This will lower financing costs and hence will benefit consumers through cheaper generation and greater reliability. On the other hand, greater reliance on such decisions may reduce market flexibility and efficiency and impose costs on consumers through regulatory failure. Different risk allocations inherent in each option require careful consideration of relative costs of regulatory and planning errors compared to the effect of high cost of capital and lack of reliability resulting from insufficient and uncertain revenues. It is important to emphasise that all the options considered in this paper retain technology, implementation, and operational risks with private investors. Further, investors will continue to compete for the opportunity to develop projects under all options.

The choice between the options will depend on judgements about the extent to which greater revenue certainty can reduce costs for investors and consumers and about the institutional capability and accountability of market bodies to implement approaches requiring greater coordination. The options can be considered to sit on the continuum from less to more assurance of cash flows and less to more coordination of different types of investment in the National Electricity Market (NEM) to ensure reliability. While all solutions offer benefits and could be implemented by 2027, coordinated auctions would likely lead to most certain outcomes, including physical security of supply and lowest power bills for consumers.

Regardless of the solution chosen, this paper emphasizes the need for a clear and transparent pathway from the end of the CIS in 2027 to the new solution. This pathway should include a well-designed transition plans, including provisions for existing assets and grandfathering arrangements, to avoid freezing investment in the NEM and halting Australia’s progress towards a near-zero emissions electricity system. Finally, the chosen solution must be accompanied by appropriate reforms to reallocate other key risks to investors that investors can’t control which are outside the remit/scope of the wholesale market design review (for example, environmental permitting and transmission buildout risk). This is essential to ensure that the benefits realized from wholesale market reform are not lost.

1 Introduction

This paper is the second in a series developed by Castalia for the Clean Energy Investor Group (CEIG). In our earlier discussion paper, we identified the reasons why the current market design was no longer able to meet the needs of consumers and producers of electricity.

Left to itself, the NEM would continue producing high and volatile prices in order to generate sufficient investment incentives. Our view is that more high and volatile prices and continued under-investment in system security and reliability are intolerable to Government and will invite government intervention. Equally, continued *ad-hoc* government interventions which rely on taxpayer funding—such as the CIS and subsidies to keep the coal generators open, should not be the answer. Such interventions depend on budget availability and tend to add to market distortions.

This paper explores potential market design solutions: that is, changes to the way investments are coordinated, and how risks are allocated and managed in the NEM, which would produce the required certainty and coordination without recourse to taxpayer support. In reality, whether risks are allocated efficiently or not, consumers and taxpayers pay for all risks even if they initially appear to fall on investors. This is because no one will commit to new investment if they do not expect to recover their target return on capital. The higher the risks allocated to investors, the higher the target returns needed to justify investment. If the risks are allocated inefficiently, consumers and taxpayers will end up paying more. The reforms considered in this paper are designed to reduce costs on consumers while getting taxpayers out of the market.

There may be a separate argument for taxpayer support for the development and scaling up of certain technologies. Such issues are not considered in this paper. Rather, this paper focuses on how to avoid having to use taxpayer funds to compensate for inefficient risk allocation under the current market design.

In subsequent sections we consider the key elements that a reformed NEM must possess. We then build on the analysis to identify potential reform options that can satisfy those key characteristics. Various submissions to the NEM review have already enumerated a long list of potential reform options. Rather than list all possible new mechanisms, we have organised our proposed options into "types"—combinations of elements and mechanisms that work together to produce the desired results. Each type can be further refined to address various specific concerns.

We conclude the paper by discussing how the choice between the type of solutions can be made.

2 Desired elements of a reformed NEM

This section describes the key elements of a reformed NEM which any solution must offer to be substantial enough to ensure efficient and reliable performance of the power market and to deliver the energy transition in time to allow for an orderly exit of coal fired generation and to protect consumer interests.

To reduce the cost of capital, risks in the NEM must be efficiently allocated to the party best placed to manage it. Investors need long-term arrangements that transfer risks which they are not well positioned to manage away from investors. Such risk transfer does not make investment in generation more profitable. In fact, it can lead to lower profitability because investors no longer have to set high hurdle rates of return if they face lower risks. Transferring risk away from investors would be efficient as long as it lowers the overall electricity system cost and results in lower power bills for consumers compared to what would have happened without such measures.

To ensure reliability, different types of investments (renewable generation, storage, firming, transmission) must be coordinated by a coordinating entity, most likely AEMO, and fully aligned. Greater reliance on planning and effective coordination provided by market bodies will be efficient if the planning errors and inefficiencies resulting from the coordinated decision-making impose less cost than the technical imbalances which may result from pure reliance on market signals.

2.1 Efficient risk allocation is necessary to minimise consumer power bills

There are a number of risks which investors are best placed to manage, such as financing, construction and operational risks. Investors are well placed to deal with cash flow risks if they fail to develop or operate their projects efficiently. However, investors are not well placed to manage broad market risks beyond their control that affect cash flow stability . These include unforeseen transmission constraints that result in curtailment, or the entry of large volumes of additional generation into the market, such as rooftop solar photovoltaics (PV). Further, from consumers' perspective, as long as most generation has very low marginal cost, there are no efficiency gains from stranding any existing generation, even if it is replaced by generation with lower capital costs.

2.1.1 Efficiently allocating risks to achieve long term cash flow stability will lower the overall cost of electricity for consumers, particularly in a grid dominated by capital intensive generation such as Variable Renewable Energy (VRE) or storage

The essence of the energy transition is that by around 2040, Australia's energy system is expected to operate largely without baseload thermal generation, relying primarily on capital intensive renewable generation and storage[1] with near-zero short run marginal cost (SRMC) of generation and only a small amount of thermal generation remaining for providing firming and peaking capacity[2].

In such a system, the cost of capital (debt financing costs and target return on equity) will become one of the key drivers of electricity costs because of the capital-intensive nature of zero or near zero emissions technologies. As a result, reducing power costs in a grid dominated by capital intensive generation requires a focus on reducing the cost of capital—specifically by lowering the cost of capital through reducing any unnecessary, excessive or unjustifiable risks

[1] The marginal cost of battery storage (essentially, the reduction in the remaining life of the battery with each charge-discharge cycle) will also be low and fixed.

[2] We use the term near zero SRMC renewable generation to refer to the large amounts of wind and solar generation that will join the NEM in the coming years. The SRMC of wind and solar is significantly lower than any competing thermal generation. In fact, the SRMC of solar generation is zero. However, wind power does have a very small SRMC—estimated by AEMO to be A$2.71 per MWh. For this reason, we refer to these generators as "near zero" for the sake of accuracy. Source: AEMO. 2019 Input and Assumptions workbook. 5 July 2020. Tab: Generator Summary -Existing, Committed and Anticipated Generators.

to investors. In fact, this would also be true in a grid dominated by nuclear power, which also has high capital costs and near zero SRMC. In essence, regardless of the technology choices, as the aging coal plants exit, future investments will involve greater capital expenditure and much lower operating costs compared to the fossil fuel dominated power system.

To lower the cost of capital, investors in the NEM require **bankable** assurances that they will have adequate and reliable long-term cashflows to service debt. In practice, this means that the market design needs to limit or remove certain market risks—such as the risks of spot price volatility or of losing the ability to evacuate electricity by subsequent investments which lead to transmission constraints—from investors. To be clear, our view is that investors should take full responsibility for the operational performance and technical efficiency of their plants as well as risks around technology choice, financing, and construction.

Table 2.1 below categorizes risks into risks within the scope of the NEM review that investors are well placed to manage efficiently and risks that investors are not well placed to manage and that could be more efficiently managed by a coordinating entity. The table also notes that there several other risks outside of the NEM review that investors are not well placed to manage that should be addressed by complementary reforms.

Table 2.1: Risks that should sit with investors in an efficient risk allocation

Wholesale market risks (within scope of NEM Review)		Risks outside of the scope of the NEM review which investors are not well placed to manage
Risks in the investors are best placed to manage	**Risks that investors are not well placed to manage**	
Financing	Curtailment risk	Permitting delay
Technology	Market Coordination	Quantum and timing of transmission investment
Construction	Lack of incentive on retailers to commit to long-term contracts	
Operations and Maintenance		

When investors are required to manage risks of spot price volatility or the risk of transmission constraints, it greatly increases the cost of capital because investors are not well placed to manage these risks. Investors are not well placed to manage them because it requires investors to manage the risk of how the project will fit together with other elements of the power system, such as the transmission system, over which they have no control. Of course, investors can and will cover these risks, but at a high cost to the NEM.

Long term cash flow stability that limits or reduces risks of spot price volatility or transmission constraints can take the form of:

- Reliable long-term contractual payments—for example, long term PPAs that offer a set price per kWh of electricity or mechanisms such as the CIS which guarantee a minimum price per kWh of electricity sold offer bankable assurances that generators or storage providers will receive adequate cash flows

- Requirements for retailers to purchase power that function as an "evergreen" contract also reduce project selection risk for investors. Examples of these types of requirements include:
  - Requirements to purchase renewable energy certificates such as the Large-Scale Generation Certificates (LGCs) required under the Large-Scale Renewable Energy Target (LRET) scheme—while the LRET does not create a long-term contract it creates an ongoing additional revenue stream for renewable energy generators that augments revenue from the spot market or contract market, improving bankability of new investment in renewable energy generation
  - Capacity payments such as those made through the Reliability Pricing Model (RPM) operated by PJM in the United States —while contracts offered through PJM's Reliability Pricing Model (RPM) are only three years long, the ongoing nature of the auctions provides some certainty that generators will continue to have access to revenue from the RPM.

Among the options for providing greater cash flow stability, those that offer more stable cash flows are the most effective in reducing the cost of capital. Long term PPAs are the most secure and as a result have helped achieve some remarkably low cost of power. For example, the Emirates Water and Electricity Co. (EWEC), which typically contracts for power through PPAs up to 30 years long, has recently announced that a project "that will combine 5.2 GW of solar with 19 GWh of battery storage to produce 1 GW of continuous baseload renewable energy…[with a] tariff would be "competitive" and in line with the rest of EWEC's portfolio."[3] This means that EWEC has signed a PPA for a GW of firmed renewable energy at a price similar to the very low cost of gas-fired generation in the United Arab Emirates (UAE).

Capacity payments or renewable energy certificates do not provide the same degree of assurance as long-term contracts. For example, the cost of LGCs under the LRET program rises and falls regularly. Nonetheless, they do provide adequate certainty to lower the cost of capital and make investments bankable, as evidenced by the success of the LRET in supporting investment in renewable energy.

We recognise that this is a significant change in the design of the NEM, which to date has pushed almost all risk of project selection onto investors. However, we believe that the trade-off of a reduction in the cost of capital will far offset any increased cost from the coordinating entity erring in project selection by creating too many LGCs or offering too many long-term contracts through a mechanism such as the CIS. In short, in a power system dominated by capital intensive generators, our assessment is that the amount consumers will overpay from 'the coordinating entity getting it wrong and overbuilding the grid' is less than what consumers will overpay because of higher than necessary cost of capital (Box 2.1). We would also stress that all other construction, siting, and permitting risks etc. would still sit with investors.

[3] https://www.pv-magazine.com/2025/01/14/masdar-ewec-announce-5-gw-19-gwh-solar-plus-storage-project-in-abu-dhabi/

Box 2.1: Risk of overbuild vs. Increased cost of capital in the market

Long-term contracts shift risks from investors to consumers because consumers continue to be liable to pay the full cost even if investment is crowded out. If PPAs are not available in the market, a central coordinating and contracting entity (such as AEMO) may step in to enter into long-term contracts on behalf of consumers. The costs of such contracts would then be spread among consumers, similar to the approach taken by the Long-Term Energy Service Agreements (LTESAs). In this setting, the risk of overbuild resulting from a mistake by the coordinating entity would be borne by power consumers. However, the greater certainty provided by such coordinated contracts should result in lower financing costs. The key question is whether the reductions in financing costs would offset potential planning errors and costs imposed by the market entity.

To assess the cost of overbuild compared to higher cost of capital in the market, we estimated both potential cost to consumers of a coordinating entity performing exceptionally badly and consistently overbuilding (for the middle case, we assume by 5 percent) to the cost to consumers of cost from higher financing costs (for the base case, we consider 100 basis points higher because of avoidable risk that is transferred to investors).

Our analysis finds that the coordinating entity consistently requiring overbuild would cost consumers an extra AUD10.9 billion between 2025 and 2050; meanwhile an extra 100 basis points on the cost of capital would cost consumers AUD$11.7 billion.

Note that this conclusion assumes that the coordinating entity is consistently wrong year after year. This is unlikely and there is no evidence to suggest that would occur; however, we have chosen this conservative assumption to demonstrate that, even with very poor planning, the cost of overbuild will be less than the cost of an unnecessary increase in the cost of capital.

We calculated the cost of overbuilding vs. an elevated cost of capital for each year from 2025 to 2050 and discounted both cost streams to present value using a discount rate of 10 percent.

- We calculated the cost of overbuilding by multiplying 5 percent of the 2024 Integrated System Plan (ISP) electricity consumption forecast by the average cost per MWh of solar PV and wind with firming estimated in the 2024-25 GenCost report. In essence, we assume that there is an additional 5 percent of wasted MWh that the firmed renewable energy could have produced and must pay for, but which are not used because the coordinating entity has over procured
- We calculated the cost of an elevated cost of capital by assuming an extra 100 basis points on the cost of capital required to finance the investment in generation, firming, and storage forecast in the 2024 ISP. For simplicity, we assume that the total investment required is divided equally between all years from 2025 to 2050 and that investments are repaid over an average economic life of 20 years.

These numbers are similar; however:

- Assuming a year-on-year 5 percent overbuild is a very conservative assumption
- We've assumed a 100-basis point increase on the cost of capital. This could be less, but it could also be more
- In the overbuild scenario, the market may have too much power (resulting in a very reliable system). In the alternative you have what we currently have (a system at risk of blackouts) for a higher cost.

In sum, even if the coordinating entity performed very poorly in project planning, Australia would still end up with a more reliable system for less money.

2.1.2 The cost burden of providing cash flow assurance should be recovered from the market, not taxpayers

Several recent interventions into the NEM have shifted the burden of providing revenue assurance to power generators from consumers onto taxpayers. For example, the CIS increases revenue certainty for investors and encourages more investment by transferring risk and cost which would normally sit with consumers to taxpayers. Further, deals struck by state governments to extend the life of the Eraring plant in New South Wales (NSW), and Yallourn and Loy Yang A plants in Victoria also shift costs to taxpayers. For example, extending Eraring, Australia's biggest coal-fired power station, for at least two more years could cost NSW taxpayers as much as $150 million a year[4], with the NSW government agreeing to cover losses up to $225 million a year.[5] While the CIS or deals to keep coal fired power stations open may appear to transfer risk and costs from investors to taxpayers, the full cost of the power system must ultimately be recovered from consumers (i.e. the costs to investors must be recovered from consumers.) Thus, in reality these interventions transfer costs from consumers to taxpayers, not investors to taxpayers.

Relying on taxpayer funds means that the burden of the power system is born by society as a whole, instead of power consumers in proportion to the amount of power that they use, raising concerns about fairness.

Further, relying on taxpayer funding is unsustainable because taxpayer funding is limited and subject to changing political trends. As a result, relying on taxpayer funding to support investment in renewable energy and storage capacity can result in the size of capacity built being dictated by available funding, rather than market need. Additionally, a change in Government can mean the end of cash flow assurance support, which can lead to a halting transition that shifts with the political winds rather than following the needs of the power system. To avoid these problems, cash flow assurance mechanisms should be scoped in size by a coordinating entity in line with the ISP to ensure they are sized correctly and the cost of providing cash flow assurance should come from power consumers in proportion to the power that they consume.

2.2 Market pricing outcomes should be socially acceptable

For a reformed NEM to be durable, market pricing outcomes need to be socially acceptable. If average costs, or even periodic power costs, are too high, Governments will be tempted to intervene in the market in ways that can undermine the overall market functioning.

The economic theory underpinning the NEM is that the NEM should call forth new investment through high spot market prices which will then be brought down as new generation and storage comes online. However, in a market dominated by capital intensive generation and storage, the uncertainty of cash flows provided through the NEM and the contracts market mean that prices must reach very high levels before investment is called forth. Investors also note that a single or several high price events are not sufficient to call forth investment, instead they require sustained high prices under the current NEM settings. For storage providers, not only must prices be high but there must also be a significant difference between low prices during the day when solar PV is producing excess electricity and high prices during shoulder periods in the morning and evening peak.

4 The Sydney Morning Herald. March 2024. Keeping the lights on at Eraring could cost taxpayers $150 million a year. https://www.smh.com.au/politics/nsw/keeping-the-lights-on-at-eraring-could-cost-taxpayers-150-million-a-year-20240327-p5ffqt.html

5 AFR. October 2024. AGL, Energy Australia coal power deals with Victoria kept secret. https://www.afr.com/companies/energy/agl-energyaustralia-coal-power-deals-with-victoria-kept-secret-20241018-p5kji8

This leads to a boom-bust cycle in generation and storage investment. For example, there has been a recent uptick in storage investment with 870 MW / 1,936 MWh worth of storage projects reaching financial commitment in the final quarter of 2024.[6] However, this comes in the context of persistently high average spot market prices, which must eventually be passed on to consumers, and the most volatile spot market prices in the world.[7]

Should prices fall in response to the uptick in investment, investment will likely pause until prices return to very high levels to incentivize new renewable energy generation and/or very volatile to incentivize new storage investment. Retailers can smooth power prices for customers to a certain extent. However, the increased hedging premiums resulting from volatility[8] in the market means that retailers smooth prices at a higher cost than if the market were less volatile.

No political system will tolerate high prices or extreme price gyrations as evidenced by the many interventions in the NEM over the last several years. Thus, even if price volatility or sustained high prices for a period of time long enough to incentivize investment is efficient, it is not politically acceptable and invites intervention in the market. Interventions then dampen investment incentives, leading to a vicious cycle. For this reason, we argue that for NEM reform to be durable, it must achieve socially acceptable, stable prices for electricity.

2.3 Improved coordination of investment to ensure physical security of supply

A reformed NEM should ensure that VRE generation is complemented by the storage and transmission required to firm VRE and achieve physical security of supply. Delivering the energy transition requires large, coordinated amounts of investment in generation, transmission, and storage to ensure physical security of supply. Physical security of supply requires that all solutions must appropriately incentivise VRE to ensure that the NEM has enough bulk energy provided from the cheapest source and dispatchable assets to ensure that power is available when consumers want it. This is materially different to the previous need to incrementally add to the power system as demand increased and price signals in the NEM called forth new investment.

Thus far, the NEM has not seen adequate investment in transmission and storage to match the increase in variable renewable energy. As a result, the NEM must rely on Australia's increasingly unreliable aging coal fleet. Under times of grid stress, this has led to threats of load shedding or blackouts. For example, on Monday November 25, 2024, AEMO warned that "up to 1.73 gigawatts of consumer electricity load could be lost on mid-afternoon on Wednesday. One gigawatt typically powers between 750,000 and 1 million homes."[9] At the same time, Australia is setting new records for curtailment of solar PV, with a record 5GW of

[6] Surge in solar, wind and battery investment sets pace for 82 pct target. Can Australia keep it up? | RenewEconomy

[7] https://reneweconomy.com.au/australias-most-coal-dependent-state-takes-title-of-worlds-most-volatile-electricity-market/#:~:text=In%20October%202023%2C%20a%20global,over%20the%20course%20of%20each

[8] Frontier Economics (2023). Future Financial Risk Management in the NEM. Available at: https://www.frontier-economics.com.au/documents/2023/12/future-financial-risk-management-in-the-nem-report-for-the-accc.pdf

[9] https://www.afr.com/companies/energy/nsw-power-squeeze-puts-market-operator-on-high-alert-20241125-p5kt7j

solar PV curtailed on September 16, 2024.[10] This strongly indicates the need for greater storage and greater coordination with transmission investment.

As described above, there was an uptick in storage investment in the final quarter of 2024 being driven by CIS commitments and very high and very volatile spot market prices which should help ease strain on the grid during peak times. However, if the gap between low prices during the day when solar PV is producing excess electricity and high prices during shoulder periods in the morning and evening peak closes and/or CIS support is no longer available, then investments in storage will cease until there is again a large gap in intra-day prices or support mechanisms like the CIS are brought back. This will bring with it the renewed threat of reduced physical security of supply.

Increasing the speed at which storage assets are built through better planning for example will reduce the length of unstable periods in the market. However, this cannot eliminate risks to physical security of supply because it is the price volatility and the accompanying insecurity of supply themselves that triggers new rounds of investment in storage.

Like unacceptably high prices for electricity, no political system will tolerate unstable power supply and will intervene if there is any threat of blackouts or load shedding as evidenced by deals struck by state governments to extend the life of aging coal plants. To avoid political intervention, the NEM requires reform that will improve coordination to smooth the required investment in firming and storage to avoid the boom-bust cycle.

Our view is that NEM reform that can deliver the improved coordination required to deliver physical security of supply will require either:

- a coordinating entity directly procuring additional dispatchable generation coordinated with transmission investment in line with the ISP—which market bodies already have considerable influence over through the Regulatory Investment Test for Transmission (RIT-T) process; or
- requiring market participants (i.e. retailers) to prove that they have contracted adequate capacity to ensure physical security of supply.

Further, any market design element aimed at increasing security of supply must be in line with the rest of the market design. For example, the intervention of extending Australia's sclerotic coal plants pulls in the wrong direction because it freezes other investment in more durable dispatchable capacity.

2.4 Be implementable by the end of the CIS in 2027

The rapidly approaching exit of coal fired generation means that any NEM reform proposed should be ready to pick up the baton by the end of the CIS in 2027 to ensure that required investment continues at the pace required to meet Australia's legislated emissions reductions goals and allow for an orderly exit of coal generation.

A clear and transparent pathway from the end of the CIS in 2027 to the overhauled market mechanisms, with adequate transition plans including provisions for existing assets and grandfathering arrangements, is required to avoid freezing investment in the NEM and halting

[10] https://reneweconomy.com.au/record-curtailment-as-rooftop-solar-reshapes-biggest-coal-grid/

Australia's progress towards a near-zero emissions electricity system. As such, any NEM reform design should be implementable in less than five years to ensure that investment keeps up the pace required for Australia to secure a reliable power supply while meeting its decarbonisation targets for the power sector. Any short-term measures recommended by the Panel must bridge the gap between the conclusion of the CIS and the implementation of the new approach and long-term vision for the NEM.

Further, the Panel, governments, and market bodies must communicate transparently on the future NEM approach (starting immediately and throughout the review process) to maintain investor confidence and ensure system reliability post-2027. Investors require timely and transparent communication to avoid freezing current investment decisions. Providing investors with clarity on the transition plan as well as medium- and long-term direction of the NEM will mitigate uncertainty, fostering investor confidence and enable Australia to accelerate its energy transition without unnecessary delays.

Box 2.2: Complementary reforms to transmission and permitting required to reap the benefit of wholesale market reform

Clean energy investors have been emphatic that reform to the wholesale market must be accompanied by commensurate reforms to areas outside of the scope of the NEM review. Key areas for complementary reform that may be beyond the scope of the NEM wholesale market review include:

- Slow environmental assessment processes through the Environmental Protection and Biodiversity Conservation Act 1999 (EPBC Act)
- Delays to State-based planning assessments
- Transmission risks (both insufficient or untimely economic approval risks, and buildout delays) including Marginal Loss Factor (MLF) risk
- Uncertainty around coal plant closure timelines

Without these reforms, projects that may be able to go ahead on a commercial basis after wholesale market reforms will be stymied by inability to receive permits or through inadequate transmission capacity. For example, WindLab reports that its planned $1.4 billion Junction Rivers project, which aimed to combine a 600-megawatt wind farm with a 200 MW, 800 MWh big battery, that was successful in the CIS tender, may fail because it has not succeeded in achieving transmission access through the Southwest Renewable Energy Zone (REZ).[11]

3 Potential solutions

To deliver the desired elements described in Section 2, our view is that more coordination is required, and that coordination should be provided by a coordinating entity whose function is embedded into the NEM. Further, our view is that in a market dominated by capital intensive generation, coordination will deliver lower cost electricity because the potential cost of overbuild is less than the additional cost imposed by higher than necessary cost of capital (Box 2.1).

[11] https://reneweconomy.com.au/andrew-forrest-backed-wind-and-battery-project-could-be-first-to-drop-off-federal-cis-winners-list/

Fortunately, the ISP produced by AEMO already provides a roadmap for what must be coordinated to deliver low cost, low emissions, and reliable electricity. Also, many of the interventions that the Commonwealth and state Governments have undertaken represent elements of greater coordination—most notably the CIS and Renewable Energy Zones. Though, ironically, many of these interventions are themselves uncoordinated as evidenced by Windlab's success in the CIS and failure to achieve transmission rights in the Southwest REZ discussed in Box 2.2.

What the NEM does not have is a comprehensive mechanism to guide the market to deliver the outcomes recommended in the ISP. To achieve that goal, there are several approaches that a coordinating entity can take:

- The coordinating entity can refrain from interfering with the market directly—in this approach a coordinating entity observes the market and procures the gap between what is required under the plan and charges retailers on a pro-rata basis for the cost of procuring the gap
- The coordinating entity can require retailers to hold certain obligations such as renewable energy certificates like the LGC or Renewable Electricity Guarantee of Origin (REGO), or dispatchable capacity such as the capacity required by PJM
- Alternatively, the coordinating entity can become a single buyer that aggregates power demand and holds auctions offering long term contracts for power supply.

Based on the archetypes above, this section proposes three potential solutions—all of which provide the desired elements of reform described in Section 2—wherein a coordinating entity, such as AEMO would coordinate the market to achieve the ISP. The three proposed solutions are:

- **Renewable portfolio standard (RPS) paired with a dispatchable capacity requirement**—this option includes a RPS aligned to the ISP and a requirement for load serving entities (LSEs) to maintain adequate dispatchable capacity. Under this solution:
  - a coordinating entity would set the RPS to match the amount required to meet Australia's legislated emissions targets—this solution could build off the LRET scheme
  - a coordinating entity would require retailers to consistently hold contracts for dispatchable capacity that match their share of peak demand plus a reserve margin—this solution could build off the infrastructure provided by the Retailer Reliability Obligation (RRO). This component of the solution would function effectively as a capacity market because a coordinating entity would require retailers to constantly hold adequate capacity
- **RPS paired with ERCOT style reserve margin**—under this model retailers must still hold obligations for renewable energy through a RPS aligned with the ISP; however, a coordinating entity would not directly require retailers to hold contracts for adequate dispatchable capacity. Instead, it observes the market, procures the gap, and charges retailers on a pro-rata basis for the cost of procuring the gap
- **Coordinated auctions**—under this option, a coordinating entity aggregates power demand and holds auctions offering long term contracts for renewable and dispatchable power supply. This solution would build off the infrastructure of the CIS,

though it would expand and tweak the CIS as well as use a different funding mechanism.

Box 3.1: Who should be the coordinating entity?

This paper does not take a definitive view of who should be the coordinating entity. However, given the roles it already plays, AEMO would be an obvious candidate. Further, placing the market operator in the role of coordinating entity would be in line with international examples such as those provided by California Independent System Operator (CAISO) and ERCOT.

Regardless of which body is chosen to become the coordinating entity (or if an entirely new body is created), the coordinating entity should have the following characteristics:

- Adequate independence to be able to carry out its coordination function without political interference
- Clear and predictable planning processes that can be investigated and replicated by market participants
- A built-in accountability function that allows for ex-post review to identify where and why the coordinating entity has erred and what reforms are required to the planning process to limit the possibility of future mistakes.

Each solution also contains an element designed to ensure adequate bulk energy—which under the ISP will largely come from VRE—and an element to ensure adequate dispatchable capacity, which the ISP envisions will be provided mostly by storage—including long duration storage.

- Each solution contains an element aimed at increasing the amount of bulk renewable energy in the grid to achieve Australia’s legislated emissions reductions targets and ensure that the system as a whole has adequate energy. This is either the RPS or auctions for renewable energy capacity.
- In recognition that most renewable energy in Australia will be variable renewable energy and that RPSs are not well suited to incentivizing storage, each solution also contains an element that will guarantee adequate amounts of dispatchable capacity. This can take the form of a requirement for LSEs to maintain adequate dispatchable capacity, a coordinating entity maintaining a reserve margin through procuring dispatchable capacity, or auctions specifically for dispatchable generation capacity—as the CIS currently does.

Further, each proposed solution would build off existing market mechanisms to shorten the amount of time required to implement each solution. This was a crucial criterion in determining which solutions to explore given the clear feedback received from the NEM Review Panel that they are looking for solutions that are implementable by the end of the CIS in 2027. For this reason, this paper does not consider the wider range of market solutions, such as implementing a capacity market or a strategic reserve, which would require creating dramatic market reform or creating new market mechanisms.

Finally, to ensure the stability and durability required to provide investors with the confidence needed to lower cost of capital, the chosen solution should be written into the National Electricity Law (NEL)/National Electricity Rules (NER) rather than introduced through legislative instruments that can be changed or halted with a change in Government. This approach will future proof the market design and insulate the efficient functioning of the NEM from political swings.

3.1 Solutions that include a renewable portfolio standard

This paper proposes two solutions that would increase the amount of renewable energy in the grid through an RPS to achieve Australia's legislated emissions reductions targets and ensure that the system has adequate energy from what Commonwealth Scientific and Industrial Research Organisation (CSIRO) has identified as Australia's least cost source of electricity. An RPS requires retailers to hold renewable certificates for a specified target share of the energy served. Such certificates can serve as effective substitutes for long-term contracts. An RPS would build off the experience of the LRET.

Box 3.2: History of the LRET Target

The Large-scale Renewable Energy Target (LRET) is part of the Renewable Energy Target. The LRET encourages investment in renewable energy power stations, like wind and solar farms, by 1) providing a financial incentive for electricity generated from renewable sources and 2) creating a market for creating and selling large-scale generation certificates (LGC). The LRET has evolved over time:

- **2001:** The Renewable Energy Target (RET) began as the *Mandatory Renewable Energy Target*. It aimed to source 2 percent of Australia's electricity from renewable sources.
- **2009:** The target was increased to the equivalent of 20 percent of Australia's electricity (41,000 GWh).
- **2011:** The RET was split into the LRET and the Small-scale Renewable Energy Scheme (SRES).
- **2015:** The LRET was reduced to 33,000 GWh in 2020 (with other targets adjusted accordingly).
- **2019:** There was sufficient capacity to meet the 33,000 GWh target in September 2019.
- **2021:** The RET of 33,000 gigawatt hours of additional renewable energy was met on a 12-month basis.
- **2030:** The last year for SRES installations and eligible renewable energy generation under the RET.

The LRET has proven to be an effective tool for increasing the amount of large-scale renewable energy in Australia's generation mix. For example, to 2022, 80 percent of new investment in the NEM had been driven by the LRET. All these projects required revenue from electricity markets and LGCs to be economic.

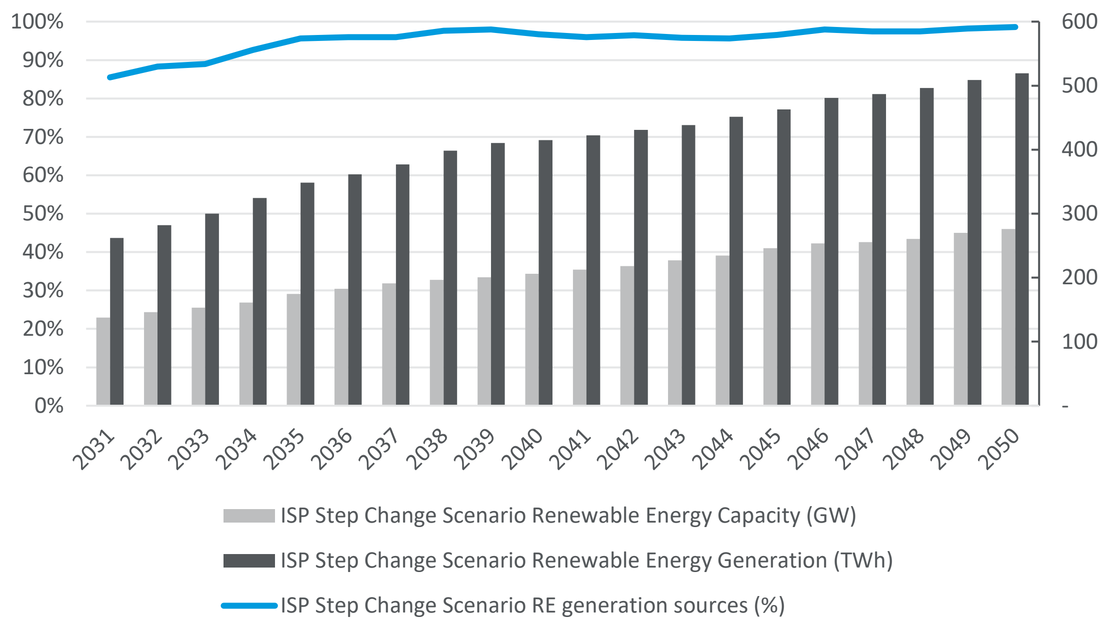
However, the current LRET target of 33,000 GWh has no linkage to Australia's target to grow the share of renewable energy to 82 percent of Australia's electricity consumption by 2030. It is linked to a target of 20 percent of renewable energy from large scale renewable energy and the LRET's ultimate target of 33,000 GWh was set as the result of a deal between the Federal Government and the Opposition, rather than in line with the ISP or Australia's legislated emissions reductions targets. [12]

This model would achieve Australia's target to grow the share of renewable energy to 82 percent of Australia's electricity consumption by 2030 and ensure enough bulk energy through increasing the RPS in each year to achieve a linear growth from current RE levels to 82 percent in 2030. The RPS for each year would be set to compliment the projected increase in renewable consumer energy resources such as rooftop solar PV.

Beyond 2030, a coordinating entity will be tasked to determine RPS required by following the ISP. As shown in Figure 3.1, this would see the percentage of renewable energy increase to nearly 100 percent by 2050.

[12] https://cer.gov.au/schemes/renewable-energy-target

Figure 3.1: ISP Step Change scenario renewable energy percent, generation, and capacity



2024 Integrated System Plan

Depoliticizing the decision on the share of Australia's electricity provided by renewable energy by allowing a coordinating entity to determine the RPS in line with the ISP would be the most effective approach for providing investors cash flow assurances because the ISP presents a clear and predictable demand for renewable energy. This approach future proofs the market design and prevents a politicized debate every election cycle about the appropriate amount of renewable energy in the NEM.

3.1.1 RPS paired with a dispatchable capacity requirement

While RPSs, such as the LRET, have been very successful in incentivizing investment in renewable energy, they have not proven well suited to incentivizing investment in storage required to firm variable renewable energy—particularly long duration storage. As a result, this solution would include a requirement for LSEs to maintain adequate dispatchable capacity including a reserve margin.

This solution would replace the RRO, which has been criticized as insufficient to incentivize investment in dispatchable capacity—including storage. However, it would seek to maintain some of the infrastructure of the RRO to avoid having to design an entirely new market mechanism.

To convert the RRO, this solution would:

- Change the definition of the reliability gap—at present, the RRO defines the reliability gap as insufficient dispatchable capacity to meet peak demand where it exceeds the 1-in-2-year peak demand forecast. As a result, the RRO is rarely in effect. Under this solution, liable entities would need to annually demonstrate that they have sufficient dispatchable capacity to meet their share of peak demand during peak hour periods in summer and winter plus a reserve margin

- Require contracts to demonstrate physical capacity to deliver—the RRO has been criticized because "the RRO doesn't require evidence that the contract seller has firm physical capacity. The seller may simply be taking a short financial risk themselves."[13] To correct this "upstreaming of risk" this solution would require that capacity contract sellers provide evidence that they have the firm physical capacity to honour the contract
- Require that contracts be long enough to incentivize dispatchable capacity—the NER requires that the Australia Energy Regulator (AER) must have regard to the principle that the contract or other arrangements should support (directly or indirectly) investment in plant or other arrangements that can supply energy that may be dispatched; or can reduce demand for energy that may be activated.[14] With that objective in mind, this solution would also require contract length to be in line with investor requirements for new investment to be financeable.

In essence, the RRO would be replaced by a significantly altered dispatchable capacity requirement that more closely resembles the resource adequacy requirement of the CAISO, by forecasting required capacity and then requiring that liable entities regularly demonstrate that they have contracted adequate capacity to meet peak demand plus a reserve margin. Under this solution, capacity requirements could also be specific to duration to encourage retailers to contract with dispatchable capacity that can serve over longer periods such as long duration storage.

The solution would leverage the existing RRO mechanism for calculating liable entities' peak demand and for determining the firmness of capacity contracts. Noting that stakeholders and AEMO have argued that the RRO's mechanisms need to be streamlined and simplified, this solution would seek lessons from CAISO on how it can more efficiently assess firmness.

This, combined with ensuring that capacity contract sellers offer physical capacity and offer capacity suppliers adequate contract length, would make this solution a much more powerful investment signal for dispatchable capacity providers than the RRO, without the need to design and implement a capacity market for the NEM or a completely new mechanism.

3.1.2 RPS paired with an ERCOT style reserve margin

Another solution that can be paired with the RPS, would be for the NEM to adopt an approach similar to the approach taken by the ERCOT to ensure that there is adequate reserve margin (meaning the amount of unused available generation capacity at peak load as a percentage of total generation capacity).

To ensure adequate reserve margin, ERCOT:

- Forecasts what reserve margin is needed to maintain system reliability—typically the reserve margin is set between 12 and 15 percent of additional dispatchable capacity that can be called on should it be required to maintain system stability
- Ensures that there is adequate reserve margin through ancillary services procured through real time, forward contract, and off-market auctions (see Box 3.3 for ERCOT's

[13] http://wattclarity.com.au/articles/2024/02/what-is-the-point-of-the-rro/

[14] *EPR0091 - Review of the RRO Final Report

approach to procuring ancillary services). Specifically, to manage reserve margin ERCOT procures contingency reserve services and non-spinning reserve service which each provide additional dispatchable capacity[15]

- Allocates ancillary services charges to LSEs based on their contribution to system demand when the services were used—crucially LSEs can avoid ancillary services charges for dispatchable capacity through demand side management and demand response which lowers their contributions to system demand or through self-supply of dispatchable capacity.

Under ERCOT's model, prices for contingency reserve services and non-spinning reserve service can rise significantly due to low reserve margins or grid stress. This creates a strong incentive for load serving entities to contract for demand side response or adequate dispatchable capacity to meet their demand to avoid ancillary services charges.

In this model, a coordinating entity would not interfere with the market directly by requiring liable entities to hold capacity contracts. Instead, it would set an explicit reserve margin target, observe if the target is being met, procure the gap—including procuring long duration storage if needed—if it sees one, and then charge retailers on a pro-rata basis for the cost of procuring the gap accounting for self-supply of dispatchable capacity.

A coordinating entity can use the existing Reliability and Emergency Reserve Trader (RERT) framework to achieve this goal. The RERT framework is similar to ERCOT's approach because it charges for the cost of meeting any reliability gap through the procurer of last resort (PoLR) cost recovery mechanism. Under the PoLR,

> *"entities whose required share of load is not covered by qualifying contracts for the specified period will be required to pay a pro-rata portion of the costs expended by AEMO to manage the market during those periods through the PoLR and may face fines for having insufficient contract as required in the NER, up to an individual maximum of $100 million per region."*[16]

In essence, this would mean that the RERT is always active. An always active RERT would provide a stronger investment signal for dispatchable capacity, including storage.

Box 3.3: How ERCOT procures ancillary services to ensure system stability and maintain the reserve margin

In ERCOT, forward contracts for ancillary services are typically short-term agreements that are intended to secure the necessary resources to maintain grid reliability in the near future. These contracts are different from the real-time ancillary services market, which deals with immediate needs, and they provide advance procurement for grid stability.

[15] https://modoenergy.com/research/ercot-ancillary-services-explainer

[16] *EPR0091 - Review of the RRO Final Report

Ancillary Service	Typical Contract Duration
Responsive Reserve Service (RRS)	Real-time (no forward contracts)
Non-Spinning Reserve Service (NSRS)	Real-time (no forward contracts)
Frequency Regulation Service (FRS)	1 to 3 years (forward contracts possible)
Voltage Support Service (VSS)	Short-term to 3 years (occasionally forward contracts)
Replacement Reserve Service (RPRS)	Real-time (no forward contracts)
Contingency Reserve Service (CRS)	Real-time (no forward contracts)
Black Start Capability	1 to 5 years (forward contracts)
Spinning Reserve Service (SRS)	Real-time (no forward contracts)

ERCOT's off-market auction contracts are typically short-term, lasting from a few hours to a few days, depending on the specific emergency need. These contracts are focused on providing grid reliability during times of system stress, such as unexpected generation losses or demand surges. The exact duration of the contracts varies based on the grid's real-time requirements, and the contracts are often designed to be flexible and renewable if needed. The longest off-market transaction contracts observed in ERCOT are in the range of 6 to 12 months for seasonal resource procurement or emergency reliability agreements, especially when there is a forecasted shortage in capacity or reliability during extreme demand periods.

3.2 Coordinated auctions

A more comprehensive approach would be for a coordinating entity to undertake comprehensive procurement of sufficient dispatchable power to meet expected demand. This approach can be visualised as a more comprehensive and transparent version of the current CIS model to ensure that the selection of the projects and procurement packages follows the Integrated System Plan and delivers an overall dispatchable and reliable system. Unlike the CIS scheme (but like the LTESA models), the costs of such procurement would be paid for by consumers.

Brazil provides an example of this approach. In Brazil, the market operator aggregates expected power demand and then holds auctions for capacity to meet expected demand—including auctions for dispatchable capacity, variable renewable energy, and reserve capacity.

In the Brazilian example, the off taker of the energy auctions is the pool of all electricity distribution companies. Each auction winner signs a different PPA with each distribution company in the pool for a fraction of the energy in each agreement. The amount each distribution utility purchases is based on their forecast of demand, and they have true-up auctions if forecasts were wrong. All costs of PPAs are passed on to consumers by the distribution utilities in their electricity tariffs.

Box 3.4: Brazil's energy auctions

Brazil's energy auction system is one of the most established and successful in the world. The system is structured around three main objectives: ensuring competitive bidding to achieve optimal prices, guaranteeing the commitment and reliability of bidders, and securing an appropriate energy mix to maintain the stability and security of the national grid. By focusing on these goals, Brazil's auctions have attracted significant investment, driving the development of diverse generation sources, including wind, solar, and hydroelectric power.

To make the auctions attractive to investors, Brazil's public authorities offer comprehensive information, including a detailed 10-year power system expansion plan. This plan outlines the projected demand and necessary infrastructure, offering transparency to developers and guiding them in determining which types of projects to pursue. The auction program, which holds auctions bi-annually, includes both generation and transmission components, enabling developers to plan for the long-term energy needs of the country and ensuring that a competitive environment is maintained during the bidding process.

Brazil's auction system includes a qualification phase to ensure that only reliable, capable developers participate in the bidding process. This phase requires bidders to demonstrate their technical and financial ability to deliver projects on time and meet energy commitments. Developers must submit proof of land use rights, environmental permits, and financial backing, while providing bid bonds to enter the auction. Winning bidders are also required to provide surety and performance bonds before signing contracts, ensuring that projects are realized as planned. To secure the optimal energy mix and ensure grid reliability, Brazil uses a combination of technology-neutral and technology-specific auctions and also conducts separate auctions for reserve capacity, ensuring that the energy supply remains balanced and secure.

Auctions are based on how long it will take to build the plant (A-6 (plants that go into commercial operation in up to 6 years' time), A-5 (in 5 years), A-4 (in 4 years) and A-3 (in 3 years)) The winners of the auction sign contracts with the distribution companies that are procuring energy with a duration ranging from 15-30 years. Total demand is aggregated, and each preferred project signs off-take contracts with each distribution company, thereby reducing payment risks through a portfolio effect. Moreover, the distribution companies include the energy cost of the distribution tariffs and transfer it to the regulated consumers.

Maurício T. Tolmasquim, Tiago de Barros Correia, Natália Addas Porto, Wikus Kruger. "Electricity market design and renewable energy auctions: The case of Brazil."Energy Policy, Volume 158, 2021, Accessed at : Electricity market design and renewable energy auctions: The case of Brazil - ScienceDirect[17]

Applying the Brazilian model to the Australian context would mean replacing the CIS with an auction program that is not time and capacity limited as the CIS is currently. Instead, a coordinating entity would mainstream an auction program into the NEM and hold regular auctions in perpetuity to procure the quantity and type of generation required to ensure that the NEM follows the ISP. As a result, a change in Government could not mean the end of the auction program.

This solution would have separate auctions for generation which would incentivize more bulk energy from VRE and for dispatchable capacity which will incentivize storage. If deemed appropriate, it could also hold auctions specifically for long duration storage.

Holding regular auctions that aim to ensure that the goals of the ISP are met will provide investors clarity on what type of projects they should develop and should ensure that the NEM has the right mixture of firmed renewable generation, storage, and bulk VRE. Further, a key finding from the Brazilian example is that "since energy auctions have been regularly performed in Brazil, investors already have a pipeline of projects planned and there is no need for a long notice period…developers thus normally have a 30-day period during which they must respond to the call for registration."

[17] *Maurício T. Tolmasquim, Tiago de Barros Correia, Natália Addas Porto, Wikus Kruger. "Electricity market design and renewable energy auctions: The case of Brazil."Energy Policy, Volume 158, 2021, Accessed at : Electricity market design and renewable energy auctions: The case of Brazil - ScienceDirect*

This solution would offer strong locational signals to generators to locate where there is adequate transmission capacity. This is because it would build off the CIS assessment criteria, which seeks to avoid supporting projects that are likely to experience heavy congestion and curtailment by including "the impact each project may have on the electricity system, including congestion, reliability, and the project's ability to provide essential system services and/or contribute to system strength" as one of the key merit criteria for assessing projects that will receive support from the CIS.[18] As a result, an auction program that covers all generation required under the ISP would greatly reduce congestion in the NEM.

PPAs with Distribution Network Service Providers (DNSPs) would not make sense in the Australian context because Australia has a competitive retail electricity market, which Brazil does not. Instead, under coordinated auctions in the Australian context:

- The coordinating agency would competitively procure long-term Contract for Differences (CFDs) with generators. The tenor of contracts for generators could be set to the life of the asset type of the auction (for example, for bulk VRE the tenor of the contract could be set to the average useful life of wind and solar PV farms). In principle, it may be possible to leave space for commercial contracting around the coordinated procurement by making CFDs cap and collar (similar to CIS) or by commencing CFDs a few years after the commercial operation date
- The coordinating entity would aggregate all generation contracted through the auctions and offer retailers fixed price load following contracts. Under this approach, retailers would have limited need for complicated hedging strategies and the secondary market for contracts would be limited as all retailers would have access to the fixed price load following contracts offered by the coordinating entity. As a result, the function of retailers may be reduced to competing on the basis of billing services, although the extent of market hedging which would still be required will depend on the design of the CFD.

Projects would still be free to find commercial counterparties[19] and to bid into the spot market as they currently do. Depending on the design of the CFDs procured by the coordinating agency, generators may be incentivised to seek out higher prices than the lower bound of the CFD (the collar), while retailers would be incentivised to contract with generators to avoid paying the higher price of the CFD (the cap). However, the CFD itself should be sufficient to bring forth adequate investment and lower the cost of capital by reducing the risk faced by investors as evidenced by the recent increase in RE projects reaching final investment decision (FID) boost in CIS supported projects reaching FID at the end of 2024.[20]

Further, under this solution, the costs of contracts offered under the auction would be recovered by the coordinating entity from retailers through the fixed-price load-following contracts who will pass those costs on to consumers. This will shift cost away from taxpayers to consumers and improve the durability of the program. As a result, the size of the auction

[18] AEMO (2024). Market Brief on Capacity Investment Scheme – National Electricity Market – Generation Tender 1. Accessed at: https://aemoservices.com.au/-/media/services/files/cis/cis-gen-nem/nem-tender-1-market-briefing.pdf?la=en

[19] https://www.energycouncil.com.au/analysis/expanded-national-cis-what-are-the-pros-and-cons/

[20] https://reneweconomy.com.au/surge-in-solar-wind-and-battery-investment-sets-pace-for-82-pct-target-can-australia-keep-it-up/

program would be determined by a coordinating entity rather than available funding from the Commonwealth.

During specific periods when the CFD is in effect consumers may pay more for electricity per kWh when the CFD collar is in effect because spot prices are below the CFD floor but will pay less when the CFD cap is in effect because spot prices are above the CFD ceiling. Consumers will not pay twice for the energy tariff and the CFD, because the CFD price will be a component of the tariff that retailers offer their consumers. Further, this paper argues that the cash flow stability provided by the CFD will bring down overall costs for consumers by reducing the cost of capital.

4 Assessing potential solutions against desired elements

This section provides our qualitative assessment of the three proposed solutions against the desired elements of a reformed NEM described in Section 2. This paper does not offer a conclusion on which option to pursue. However, we assess that, while all solutions offer benefits (and drawbacks) and could be implemented by 2027, coordinated auctions would likely offer the greatest long-term stability of cash flows, lowest price outcomes for consumers, and improve coordination to ensure physical security of supply. Table 4.1 summarizes our qualitative assessment of each of the three investigated solutions against the five desired elements of a reformed NEM.

Table 4.1: Assessing Potential Solutions against desired elements of a reformed NEM

	Long-term cash flow stability		*Physical security of supply*	*Improved Coordination*	*Acceptable Market Pricing Outcomes*	*Ease to Implement*
	Bulk VRE	*Storage*				
RPS+ dispatchable capacity requirement	*Med*	*Med*	*Med*	*Low*	*Med*	*Low*
RPS+ Reserve Margin	*Med*	*Low*	*Med*	*Med*	*Med*	*High*
Coordinated Auctions	*High*	*High*	*High*	*High*	*High*	*Med*

**In this chart high is the best rating*

All solutions will increase long-term cash flow stability; however coordinated auctions will increase long-term cash flow stability the most

Coordinated auctions under long-term contracts provides the highest long-term cash flow stability and would lead to the greatest reduction in the cost of capital. Coordinated auctions removes spot market volatility risk from investors because successful projects under the auction program will have guaranteed minimum revenues for electricity they sell. A potential downside of increased long term cash flow stability and assurance provided by coordinated auctions is that it may eliminate or restrict contracting market. In principle, coordinated contracts would replace the need for private contracting. However, the absence of a liquid private market may lead to inefficiencies. Some market liquidity may be preserved by designing CFDs in such a way as to leave space for market-based management of risk without undermining the risk-management benefits of the CFDs.

RPSs have been proven to provide an adequate level of long-term cash flow stability for bulk VRE, as evidenced by the success of the LRET in incentivizing renewable energy to date. An RPS should therefore likely be successful in bringing forth investment in bulk VRE. However, as evidenced by the fluid nature of LGC prices under the LRET, RPS are not as secure a guarantee as offered by an auction program with a cap and collar CFD contract. Further, an RPS does not necessarily offer a mechanism for managing curtailment unless the RPS would allow curtailed generators to still receive cash flows for curtailed energy, which would greatly increase the cost of the RPS and is therefore unlikely. Hence, the RPS will not likely reduce the cost of capital as much as a coordinated auction program.

For storage, a dispatchable capacity requirement would provide some long-term cash flow stability because liable entities would need to demonstrate that they have contracted enough dispatchable capacity at all times. This will create an incentive to contract with storage providers. Meanwhile, a reserve margin associated with a more active RERT would provide only a low amount of long-term cash flow stability, because during periods where there is adequate reserve margin, there would be no need for a coordinating entity to contract with storage providers under the RERT.

Coordinated auctions will provide the lowest price outcomes because it provides the greatest long-term cash flow stability and reduces the cost of capital

As argued in Box 2.1, our view is that a greater degree of coordination will lead to a lower-cost power system overall because greater coordination will offer the greatest long-term cash flow stability by efficiently allocating risks. This will lower the cost of capital which is the key determinant of electricity price in a market dominated by capital intensive generation technology. A coordinated auction program would offer the greatest degree of coordination and long-term cash flow stability by removing market volatility risk. As also noted in Box 2.1, could result in higher prices to consumers if the coordinating entity dramatically underperforms. While we believe this is an unlikely outcome, this does present a political risk as well as a risk to consumer budgets and we encourage the Panel to design this mechanism in ways that mitigate this risk (for example through design features of the coordinating entity, how it functions, and/or the presence of balancing checks).

The RPS plus a dispatchable capacity requirement or an ERCOT style reserve margin should also result in more acceptable price outcomes because they will both reduce the cost of capital by providing a degree of long-term cash flow stability to both generation and storage. Further, both solutions will reduce periods of constrained supply that cause spikes in power prices on the spot market.

Coordinated auctions by their nature would provide the greatest degree of coordination of investment

Coordinated auctions clearly offer the strongest ability for a coordinating entity to coordinate bulk VRE, dispatchable capacity, and transmission through placing conditions on when and where new capacity would be built when determining winners of auctions based on where projects need to be built to minimise total system costs. As mentioned above, the CIS already includes a mechanism to ensure new generation does not increase congestion by assessing "the impact each project may have on the electricity system, including congestion" as one of the merit criteria for assessing projects that will receive support from the CIS.[21] Further, an auction program that covers the whole NEM will likely reduce congestion because the auction scheme considers the impact each project may have on congestion.[22] As a result, projects that are likely to cause congestion, and as a result curtailment, are unlikely to proceed as they will not receive support in the auction program. However, this may result in decreased creativity from the private sector in pursuing innovative investments in generation if they are not included in the coordinated auction program.

The RPS plus a reserve margin would allow the coordinating entity some discretion by choosing who it contracts with through the RERT. This would provide some degree of influence on where new dispatchable capacity is built. Further, under a dispatchable capacity requirement the coordinating entity could consider the likelihood of curtailments when determining the firmness of capacity contracts. This would provide a signal for generation, dispatchable capacity in particular, to locate where there is adequate transmission capacity. However, both solutions would not allow the coordinating entity to improve coordination directly, whereas coordinated auctions would.

Coordinated auctions would provide the greatest degree of physical security of supply

As noted in Section 2.3, physical security of supply requires that all solutions must appropriately incentivise VRE to ensure that the NEM has enough bulk energy provided from the cheapest source and dispatchable assets to ensure that power is available when consumers want it.

Our assessment is that coordinated auctions would provide the highest physical security of supply because the coordinating entity would have the greatest degree of control over the level of investment in both bulk energy and dispatchable capacity through determining the size and frequency of CIS tenders. The coordinating entity may err and procure too little capacity; however, international experience suggests that this is unlikely and true-up auctions, similar to those conducted in Brazil, could be used to bring on more capacity quickly. It is more likely that the coordinating entity will over procure marginally (though less than the conservative 5% used to calculate cost of over procurement in Box 2.1) which would have costs for consumers; however, it would lead to a very physically secure system.

Both the RPS plus a dispatchable capacity requirement and an RPS plus an ERCOT style reserve margin, would provide greater physical security of supply because RPSs are able to incentivize VRE which would provide the required bulk energy. However, neither a dispatchable capacity requirement nor an ERCOT style reserve margin provide as strong an inventive for dispatchable capacity as coordinated auctions would. For example, during the Energy Security Board's (ESB) consultation on expanding the RRO, several storage providers and generators questioned if an RRO in any form would provide much of an investment incentive.[23] Further, ERCOT has faced calls to develop a capacity market mechanism in the aftermath of winter storm Uri.[24]

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[21] AEMO (2024). Market Brief on Capacity Investment Scheme – National Electricity Market – Generation Tender 1. Accessed at: https://aemoservices.com.au/-/media/services/files/cis/cis-gen-nem/nem-tender-1-market-briefing.pdf?la=en

[22] AEMO (2024). Market Brief on Capacity Investment Scheme – National Electricity Market – Generation Tender 1. Accessed at: https://aemoservices.com.au/-/media/services/files/cis/cis-gen-nem/nem-tender-1-market-briefing.pdf?la=en

[23] 2021-June-Summary-of-Stakeholder-Feedback-compressed.pdf

[24] https://www.sciencedirect.com/science/article/pii/S0140988324005188

All proposed solutions are implementable by the end of the CIS in 2027

This paper has purposefully proposed solutions that build off or expand existing market mechanisms to avoid, as much as possible, an extended design process. However, of the three options, we assess that the RPS plus a reserve margin would be the easiest to implement because it requires the least change to the NEM.

A RPS plus a reserve margin would be the easiest solution to implement because the LRET and the RERT are existing mechanisms upon which it could build. Further, the RERT requires the least complex capability from the coordinating entity and the coordinating entity can draw on the experience of ERCOT for reserve margin forecasting. Finally, the RERT is not as invasive for retailers and generators to implement because it does not require them to demonstrate that they have contracted adequate capacity or offered contracts for dispatchable capacity. The trade-off is that while the RPS plus a reserve margin is the easiest to implement, we also assess that it provides the weakest long-term cash flow stability for storage and a weak ability to coordinate investment to ensure physical security of supply compared to coordinated auctions.

We note that while an RPS plus a dispatchable capacity requirement also expands on the existing and understood mechanisms of the LRET and the RRO, enhancing the RRO received considerable pushback from the industry during ESB consultation on expanding the RRO, leading the ESB to abandon the effort. It remains to be seen if a mechanism built off of the RRO, even with significant alterations, would be received differently in the context of a more comprehensive market reform. Further, commentators have noted that the existing RRO's formula's for assessing the firmness of, what are sometimes bespoke, capacity contracts is a complex time-consuming process.[25] Thus, a replacement for the RRO that requires load serving entities to always demonstrate that they have adequate dispatchable capacity that extends to the whole market would require considerable additional resources. For that reason, we assess that an RPS paired with a dispatchable capacity requirement would be moderately difficult to implement.

Finally, coordinated auctions relies on three building blocks which AEMO already delivers: the LTESA, the ISP, and the existing CIS. As a result, it would not require additional skillsets, nor would it likely require a significant increase in personnel from AEMO should AEMO be given responsibility to be the coordinating entity. However, a coordinated auction program that would be large enough to deliver the ISP in perpetuity would require institutional reform to enable the coordinating entity to perform this function with the appropriate degree of transparency and accountability. It also may require changes to contract templates (such as offtake counterparties taking curtailment risk or negative pricing risk) which would potentially add costs to consumers.

5 Conclusion

A reformed NEM must deliver improved coordination, physical security of supply, and long-term cash flow stability to investors to deliver socially acceptable market pricing outcomes. Further, costs must be shifted away from taxpayers for any NEM reform to be sustainable.

[25] http://wattclarity.com.au/articles/2024/02/what-is-the-point-of-the-rro/

The three proposed solutions differ in the degree of risk and reliance on a coordinating entity. The options we consider offer different trade-offs between the degree of market flexibility in responding to price incentives compared to certainty and reliability of outcomes. Different risk allocations inherent in each option require careful consideration of relative costs of regulatory and planning failures compared to the effect of high cost of capital on consumers.

This paper does not offer a conclusion on which option to pursue. However, we assess that, while all solutions offer benefits and could be implemented by 2027, coordinated auctions would likely offer the greatest long-term cash flow stability, lowest price outcomes for consumers, and improve coordination to ensure physical security of supply.

Regardless of the solution chosen, this paper emphasizes that a clear and transparent pathway from the end of the CIS in 2027 to the new solution, with adequate transition plans including provisions for existing assets and grandfathering arrangements, is required to avoid freezing investment in the NEM and halting Australia's progress towards a near-zero emissions electricity system.

Finally, the chosen solution must be accompanied by appropriate reforms to transmission planning and project approvals processes—including assessment processes through the Environmental Protection and Biodiversity Conservation Act 1999 (EPBC Act)—to ensure that the benefits that will be realized from wholesale market reform are not lost due to inability to receive permits or inadequate transmission infrastructure.

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