

Coordinating coal plant closures: transient strategic reserves in transitioning energy-only markets

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January 2026

Abstract

During 2016-2018, Australia's National Electricity Market (NEM) experienced the adverse effects of two sequential and sudden coal plant closures, viz. sharply rising wholesale spot prices, structural hedge shortages and deteriorating system strength. More recently, a slowing rate of renewable project entry has led governments to intervene by delaying scheduled coal plant closures. An intervention to delay a scheduled coal plant closure helps maintain short-term reliability but inadvertently undermines investor confidence in new entry through a transient depression in near-term forward prices. Above all, interventions risk reinforcing a cycle of stalled renewable entry and further delays to scheduled coal plant closures. This article analyses a transient strategic reserve, a deliberately temporary, out-of-market "waiting room" for new dispatchable capacity to break the circularity. By assembling and temporarily underwriting a targeted reserve of dispatchable plant prior to coal closure dates, policymakers can maintain price stability and resource adequacy while substantially preserving the integrity of the energy-only market design. Using a dynamic, security-constrained electricity market model, outcomes across scenarios show the transient reserve produces a more orderly transition path, materially reduces the risk of price volatility and reliability breaches at relatively low cost, while improving investment incentives for intermittent renewables and dispatchable plant capacity. Findings suggest "the waiting room" is a tractable, low-intrusion mechanism capable of supporting scheduled coal closures without institutionalising a capacity market.

Keywords: strategic reserve, energy-only markets, resource adequacy.

JEL Codes: D52, D53, G12, L94 and Q40.

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1. Introduction

When Australia's National Electricity Market (NEM) commenced in 1998, coal-fired generation dominated the aggregate supply function with a market share of 92%. The NEM was the world's most coal-intensive power system, and by implication, faced amongst the world's most complex decarbonisation tasks. Policymakers made eight formal attempts at introducing a price on power system CO₂ emissions to help guide investment commitment, but each ended in failure (Jones, 2014; Nelson, 2015; Crowley, 2017, 2021). Despite the divisive policymaking environment, steady progress was made with coal generation's share now ~51% and falling due to the success of Australia's certificate-based 20% Renewable Energy Target or 'RET' (Nelson et al., 2025).

By the early-2020s, the RET had facilitated 176 wind and solar projects totalling 26 GW (for context, power system maximum demand is ~37GW). Additionally, the RET was also largely responsible for triggering the NEM's 24GW rooftop solar fleet along with (by far) the world's highest take-up rate of rooftop solar PV.

Yet investment in utility-scale renewables visibly slowed from 2023 as Fig.2 later reveals. A slowdown of this magnitude involves many variables going wrong all at once including a tightening of environmental approvals in 2022 and other permitting frictions (Clapin and Longden, 2024), sharply rising costs of onshore wind from 2022 (Simshauser & Gilmore, 2026b) and the introduction of an awkwardly defined CfD scheme which ostensibly supplanted on-market demand for PPAs (Flottman et al., 2025). But another variable, government interventions to delay scheduled coal plant closures (Simshauser, 2026), has compounded matters and weighs on investor (and PPA buyer) sentiment. These interventions have a highly problematic circular reasoning:

- Credible coal plant closure schedules by private or public utilities are a material market announcement. The average capacity of coal plant in Australia is ~1500MW. Exit creates room in the market for new (non-subsidised) renewable projects to enter on an economic basis. Credible coal closure timelines can therefore be expected to accelerate investment commitments in intermittent renewables and dispatchable (i.e. firming) capacity. This is far more than a theoretical observation¹.
- However, if anticipated entry begins to slow for any reason, jurisdictional governments must intervene² and delay scheduled coal plant closures to maintain both security of supply and price stability – particularly given the political economy of electricity tariff increases in a *cost-of-living crisis*.
- When credible coal closure schedules are formally delayed by way of intervention, and the practice emerges as a pattern, it has the effect of foreclosing new entrants. The complexity of arranging new entrant power projects (including supply chain constraints) means reactivating stalled projects is far from assured given time-inconsistent policy settings.

A pattern of interventions to delay scheduled coal plant exit transforms '*closure commitments*' to '*quasi-closure commitments*'. There are no winners from quasi-closure commitments:

¹ In the NEM's Queensland region prior to the coal exit schedule announcement, there were 26 renewable projects comprising 8.5GW actively seeking to reach financial close. One year after the exit schedule was announced in 2022, the pipeline swelled to 78 projects comprising 35+GW with 9+GW of projects reaching financial close within three years.

² Various coal plant underwriting policies or direct interventions to delay closures have now occurred in New South Wales (2000MW Liddell in 2020, 3000MW Eraring in 2024), Victoria (1450MW Yallourn under-writing commitment in 2021) and Queensland (700MW Callide B in 2025).

- For potential new entrant investors, government interventions introduce pronounced near-term uncertainty over future spot prices, the value of forward derivatives (including PPAs), and renewable ‘curtailment rate’ risks (given coal plant inflexibility).
- For consumers, the circularity involved in *quasi-closure commitments* avoids a near-term problem. But given an aging coal fleet, continuous delays to scheduled closures introduces the risk of rising equipment failures and commensurate price shocks (as Fig.1a and 1b subsequently reveal).
- For governments, stated renewable policy targets become intractable and the very risks facing the consumer base may ultimately transfer to serious political and public administration risks.

How can policymakers break this circularity in Australia’s NEM (and other jurisdictions facing lumpy exit schedules) given a residual coal fleet of ~20GW, i.e. 15 large thermal generators which eventually need to exit? Academics and policymakers in European electricity markets have dealt with analogous scenarios during the 2010s. Acute merit order effects from renewables strained the economics of incumbent, but requisite, peaking plant (Kozlova et al., 2023). This triggered debates on market fundamentals including whether the energy-only market design should transition to a capacity and energy market, or zonal setups should transition to nodal pricing, and so on. A minimal or ‘low intrusion’ option adopted in certain jurisdictions was a ‘strategic reserve’ (Holmberg and Tangeras, 2023).

By definition, a strategic reserve comprises an administratively determined level of ‘out-of-market’ emergency plant designed to ensure security of supply (Neuhoff et al., 2016). To minimise unintended consequences and distortionary impacts of administrative decisions, strategic reserves are annexed from the market, and only dispatched under critical conditions, specifically, when the incumbent fleet of market generators are exhausted and unable to meet aggregate final demand (Lo Prete et al., 2025). A strategic reserve thus represents a *surgical option* with at least three desirable features:

1. Plant within the strategic reserve are the only participants receiving an administratively determined capacity payment, meaning scheme costs should be small.
2. A strategic reserve policy can be turned off as quickly as it is turned on – meaning there are no *institutional dependencies*.
3. At certain times, power system need for new (e.g. reserve) plant presents as stronger and clearer than a commercial case for investment.³ Under these conditions, in theory at least, a strategic reserve pulls forward what the market would eventually deliver in a least cost power system, while at the same time helping to smooth the energy transition.

The primary downside to a strategic reserve is how it is used. Such plant should not be used to influence clearing prices. However, in adverse market conditions, the political temptation for over-use or actively manage spot prices must be non-trivial, and this is to be acknowledged upfront. With such a policy proposal, the as Neuhoff et al., (2016) explain, the details matter.

In this article, a *transient strategic reserve* or ‘*waiting room*’ – an explicit, temporary and out-of-market portfolio of dispatchable plant capacity underwritten with a revenue floor – is assembled to break the NEM’s delayed entry/delayed closure circularity problem. By assembling a targeted reserve of new dispatchable plant ahead of scheduled coal plant closures, governments can maintain confidence in

³ I should acknowledge Aurecon’s Managing Director - Energy, Paul Gleeson, for this astute observation about investment patterns in Australia’s NEM.

the likely stability of the post-exit environment while simultaneously avoiding distortions associated with ongoing market interventions. Once the (pre-emptive) transient strategic reserve is fully subscribed and delivered, coal closures may proceed as scheduled, and the fleet of generators comprising the strategic reserve would exit the waiting room and transition into the market (i.e. 'in market'), thus supporting an orderly and predictable transformation without institutionalising capacity market arrangements.

A waiting room adds to the menu of policy options available policymakers to deal with a scheduled coal plant closure vis-à-vis price volatility, reliability, and investment incentives given *the political economy of electricity supply*. Using an electricity market model, this article examines the policy options including (1) exit before entry (2) accelerated renewable entry via CfD underwriting, (3) delays to scheduled coal plant closures, and (4) the waiting room or transient strategic reserve.

It is to be noted that the political economy of a scheduled coal plant closure, and the possibility of government intervention, is treated as exogenous in the modelling. This reflects the practical difficulty of modelling political decision-making within a partial-equilibrium framework, and the research objective of isolating market consequences of alternative policy responses following intervention. In practice, the political economy of unacceptable price volatility and perceived planning failures that may arise with breaches of stated reliability standards are a binding constraint on government, and therefore government behaviour. The scenario-based approach adopted in this article is not intended to imply government passively selects from a menu of policies, but rather, works through dominant responses that are observed in practice, viz. unplanned exit, accelerated renewable entry by way of CfD auctions, and delays to scheduled coal plant closures. Holding government behaviour fixed across scenarios highlights the costs, benefits and unintended consequences of plausible responses under conditions of a scheduled coal plant closure.

Model results suggest that developing an alternate policy option, viz. the 'transient strategic reserve' presents as a more tractable response that helps navigate the political economy of price volatility and reliability constraints in the presence of lumpy coal plant exit. Above all, results remain consistent with sound (long run) power system planning in a transitioning energy-only market setup, and perhaps surprisingly, may serve to meet immediate or short run political expediency.

This article is structured as follows. Section 2 provides a primer on the dynamics of coal plant closures in Australia's NEM. Section 3 follows with a review of literature. Section 4 presents brief overview of the model while Section 5 presents model results. Policy implications and concluding remarks follow.

2. A primer on NEM coal plant closures

In Australia's NEM, 11 coal plants totalling more than 7 GW have exited in a system with a maximum demand of 37GW. The average plant size at exit was 700 MW (Nelson, 2018). At the time of writing, 15 coal plant comprising ~20 GW remains with an age-weighted exit size of ~1500MW. The closure task facing the NEM is thus becoming more complex. State Governments in Australia have first-hand experience of the adverse effects of two rapid coal plant closures in South Australia (2016) and Victoria (2017):

1. In South Australia, pre-exit advice to government was the system would maintain a reliable supply. The lived experience in the post-exit environment was a structural shortage of hedge contracts (Flottmann et al., 2024) which adversely impacted on the retail supply market, followed by a state-wide black system event (Clapin and Longden, 2024). While the underlying cause of the disturbance was not related to capacity shortages arising from the coal plant

closure, a lack of inertia meant underfrequency load shedding relays were incapable of dealing with the plunging Rate of Change of Frequency (Simshauser and Gilmore, 2022).

2. In Victoria, a 1.6GW coal plant closed with five months' notice, with wholesale market prices doubling in the post-exit environment (Gonçalves and Menezes, 2022).

This context is important. It helps explain why state governments in Australia's NEM *are sensitive* to scheduled coal plant closures. Government intervention understandably reflects concern vis-à-vis resource adequacy, noting the State – and the Energy Minister – will ultimately be held accountable in an energy market crisis (i.e. elevated prices, breaches to security of supply, or both).

2.1 The circular problem of *quasi-commitments*

Government decisions to delay scheduled coal plant closures are material events. Coal plant seeking to exit will have exceeded its engineering design life and will exhibit rising total (planned and forced) outage rates (Fig.1a). If a plant has been scheduled for closure, intuitively, maintenance practices in immediate prior periods may resemble 'run-to-fail' mode. Delaying scheduled closures is therefore likely to extend plant with already high failure rates. And, for plant >40 years of age, total outage rates are already high as Fig.1a suggests. Fig.1b highlights the remaining fleet 'MW-weighted' average age is now 39 years (note in Fig.1b the 'retired' fleet MW-weighted average age was 44 years).

Figure 1a: NEM coal fleet total outages rates (2005-2026)

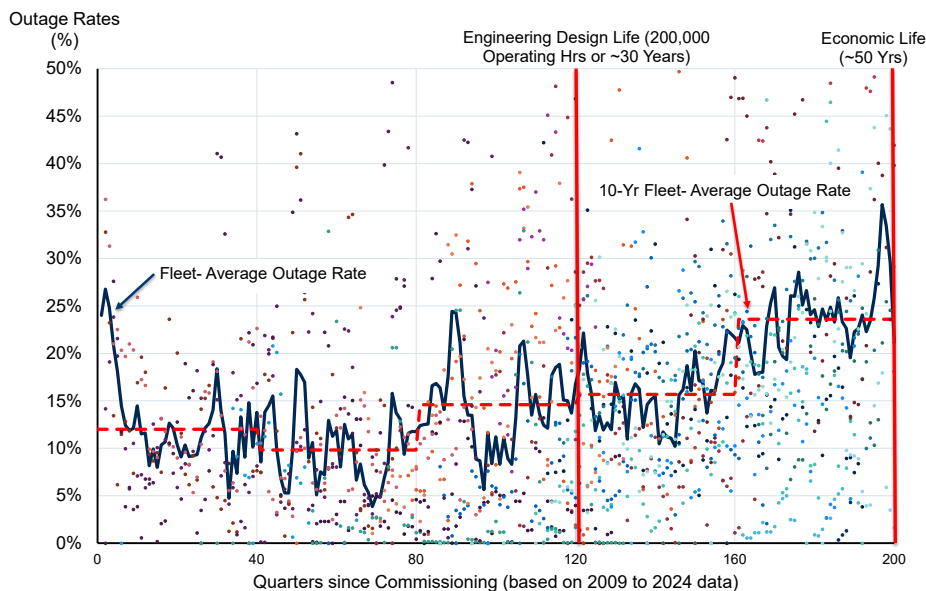
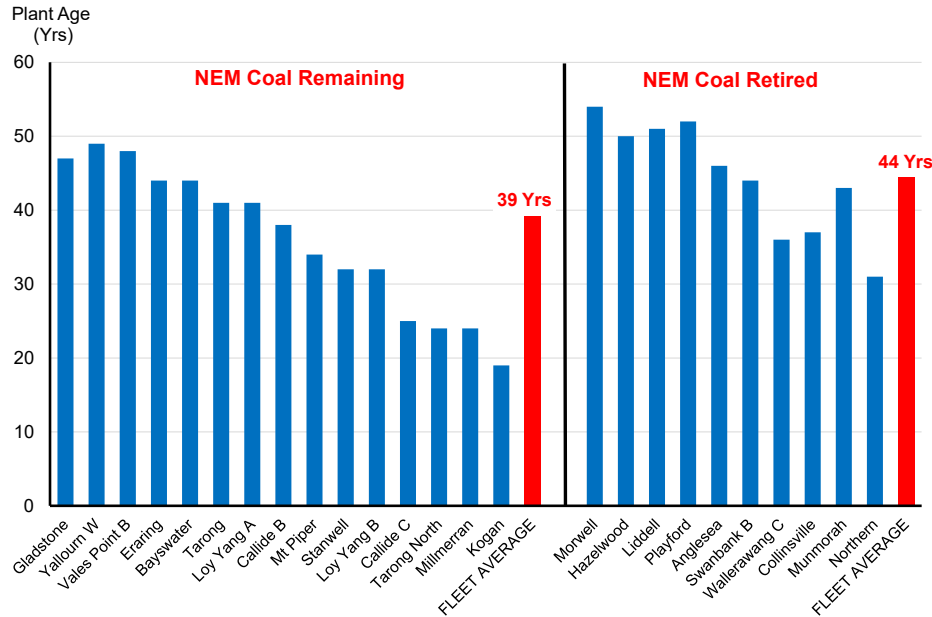


Figure 1b: Age of the NEM Coal Fleet (as at 2026)



However, the more significant issue is the circular nature of the intervention. A government will intervene to delay a scheduled coal plant closure because the supply-side appears inadequately prepared for the post-exit environment. Interventions usually involve a form of taxpayer-funded underwriting of the coal plant life extension. And the inflexibility of coal plant means during the extension period:

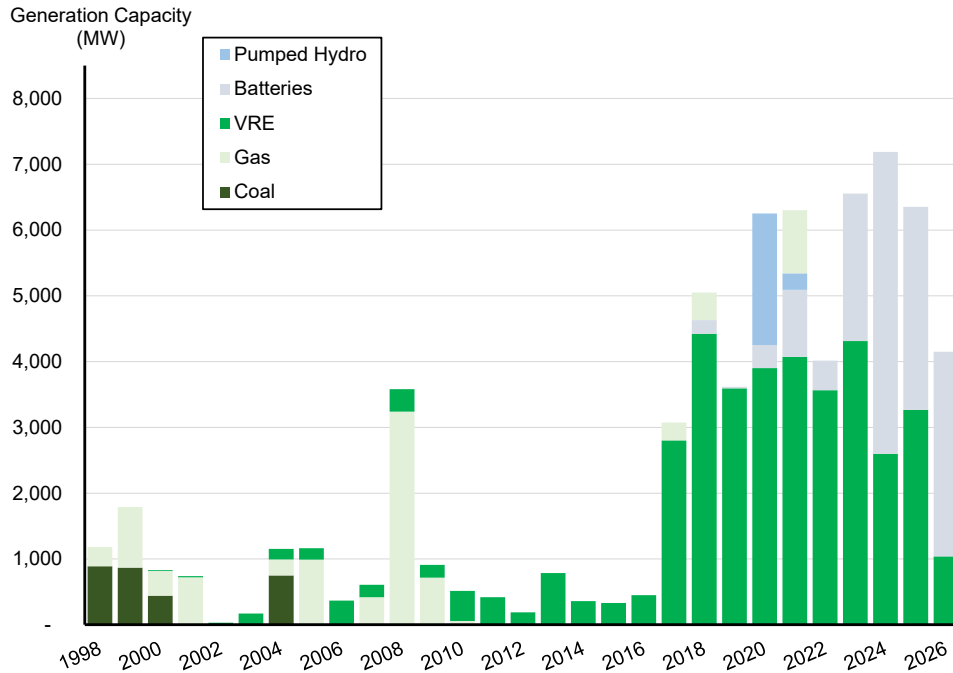
- negative price events in solar-rich periods will be intensified due to the collision between aggregate coal plant minimum stable loads and the NEM's vast solar fleet.
- curtailment rates of semi-dispatchable wind and solar PV plants will rise,
- being a semi-strong efficient market, any 'delay announcement' will be immediately priced into forward markets, adversely impacting near-term profitability of PPAs, and therefore
- the logical response by investors is 'to wait'.

These unintended, albeit predictable, consequences mean requisite investment in new entrant plant (i.e. wind, solar, batteries, pumped hydro, gas turbines) may become more difficult to close out. If plant doesn't enter in a timely manner, the intended length of delay to a scheduled coal plant closure may be further extended. Thus is the circular reasoning of the problem.

2.2 The slowing of renewable investment commitments

There has been a distinct slowdown in the flow of renewable investments in Australia's NEM from 2023 (see Fig.2, Variable Renewable Energy or 'VRE'). Reasons for this slowing include planning and environmental permitting delays, policy discontinuity disrupting the run-of-trade of bilateral Power Purchase Agreements (PPA), sharply rising costs for wind – and of course – delays to scheduled coal plant closures weighing on investor sentiment (Nelson et al., 2023; Clapin and Longden, 2024; Simshauser & Gilmore, 2026b).

Figure 1: NEM plant investment commitments by technology (1998-2026)



In mid-2023, the Commonwealth Government stepped-in and announced a ‘*Capacity Investment Scheme*’. (Billimoria et al., 2025) The Scheme initially involved taxpayer-funded government-initiated auctions for CfDs to facilitate investment in dispatchable capacity. Curiously, GTs – the power system’s fast and flexible last-line of defence – did not qualify. And given the development lead times of pumped hydro projects, they were constructively excluded. Consequently, utility-scale batteries became the sole qualifying technology.

In late-2023, with utility-scale renewable investment commitments visibly stalling (Fig.2) the Scheme was greatly expanded to include +23GW of intermittent renewables, while the dispatchable capacity category was expanded from 6 to 9GW (GTs still excluded). Thus far, almost 20GW of Commonwealth CfDs have been announced but at the time of writing, Rystad Energy (2025) data revealed only 3GW of projects across all categories had reached financial close⁴ - meaning the Scheme has not yet facilitated the entry of the requisite mix of plant capacity necessary to enable coal plant closures. It may also unintentionally dis-intermediated the bilateral market for PPAs (Flottmann et al., 2024; Flottmann et al., 2025).

3. Review of Literature

As problems mounted, Energy Ministers from the Commonwealth and State Governments commissioned a review of the wholesale market by well-known Australian electricity industry executive and academic, Associate Professor Tim Nelson. The final report had two recommendations critical to this research:

1. The NEMs energy-only remains fit for purpose; and

⁴ Ironically, Rystad Energy data also suggested more than half of this capacity had already reached financial close or had a bilateral PPA in any event.

2. Incomplete forward markets require policy adjustment to deal with a ‘tenor gap’ that exists between the credit time horizon of project banks (10-15 years) and forward market liquidity (1-3 years). Additionally, the Review identified an option for a conventional (i.e. standing) strategic reserve.⁵

3.1 On the energy-only market design

As Petit et al., (2017) explain, a well-designed energy-only market in which the spot market price cap has a close relationship with reliability criteria will produce broadly the same reliability outcomes as an energy and capacity market. Billimoria et al., (2025) highlight one of the quintessential design elements of energy only markets as ‘full strength pricing’ – viz. price spikes are a feature rather than a problem to be solved by regulatory authorities. Yet the literature highlights that while in theory the energy-only market is preferred (i.e. less administrative decisions), the conditions under which this arises are difficult to achieve in practice (Bialek *et al.*, 2021).

The outcome is persistent concerns regarding ‘resource adequacy’ – i.e. the timely entry of requisite new plant to deliver a near optimal plant mix that ensures a reliable supply. Key frictions include administratively determined market price caps set too low (Cramton and Stoft, 2008), capricious regulatory interventions aimed at suppressing legitimate price spikes (Hogan, 2013), elongated business cycles which substantially deviate from long run equilibrium (Arango and Larsen, 2011; Bublitz *et al.*, 2019), and largely inelastic aggregate final demand (Roques, 2008).

The introduction of a large fleet of VRE generators with near zero marginal running costs is thought to complicate the task of resource adequacy considerably in energy-only markets (Hirth et al., 2016; Joskow, 2019). Although, when demand elasticity and storages of various durations are incorporated, modelled results better reflect current transitioning market outcomes, which suggests energy-only markets don’t *necessarily* continuously deteriorate as VRE increases (Brown et al., 2025).

Incomplete forward markets are thought to be amongst the more significant entry frictions (Grubb and Newbery, 2018; Nelson et al., 2023). A liquid market for 15-year PPAs would ameliorate most of these risks. But the combination of Newbery’s incomplete forward markets (i.e. the tenor gap) and risk averse capital market participants raises concerns over revenue certainty. Indeed, combining incomplete markets with indeterminate payback periods of power generation plant means as investments, they frequently span the credit time horizon of the capital markets (Offer, 2018; Simshauser and Gohdes, 2025).

Collectively, these parameters create observed risks for timely investment (Cramton and Stoft, 2006; de Vries and Heijnen, 2008). And peaking plant, whose spot market revenues are randomised at best, are most vulnerable yet are critical preconditional entrants for a scheduled coal plant closure (Peluchon, 2003; Bajo-Buenestado, 2017; Keppler, 2017).

These concerns parallel those of the 1890s. When electricity systems were first developed, a single energy price was charged to consumers. But peaking duties of the system were sending the London and New York utilities towards insolvency (Hopkinson, 1892; Greene, 1896). The two-part tariff, which split energy prices into a fixed capacity rate (\$/kW) and a variable energy charge (\$/kWh) emerged as a stable and durable solution. The dominant wholesale market design in the US comprises a capacity and energy market, where spot markets are supplemented with fixed capacity payments as a means by which to ensure generation plant is adequately remunerated and enters on a timely basis (Holmberg and Tangeras, 2023).

⁵ The 2025 NEM Review is available at [National Electricity Market wholesale market settings review](#).

However, energy and capacity markets have their own frictions. As Neuhoff et al., (2016) explain, details matter with capacity markets and are often characterised by over-procurement and elevated prices. Indeed, (Bialek *et al.*, 2021) argue that conventional capacity markets may be incompatible with transitioning power systems because structurally, they annex too much of total market revenues to fossil plant, and their lower spot market price caps constrain the entry of storage (cf. energy-only markets).

The Nelson Review into Australia's NEM targeted Newbery's *incomplete markets problem* while being mindful of the over-procurement problem. The Review team developed a mechanism to solve for both problems, viz. a centrally coordinated auction mechanism designed to bridge the tenor gap between visible forward (i.e. 0-5 years) and the credit time horizon of project banks (i.e. 15 years). That is, auctions would make available long-dated reference PPAs (i.e. structured as tradable derivatives) but with a start date from year 6, thus ensuring the NEM's liquid forward markets continue to guide investment requirement timing. Drafting of the mechanism will no doubt follow once Energy Ministers approve the scheme. But the circularity of coal closure *quasi-commitment* would appear to be unresolved.

3.2 The quasi-closure commitment problem

The Nelson Review recommendations appear more than capable of dealing with incomplete markets and the credit time horizon problem. But it may not resolve the *quasi-closure commitment* problem, that is, government interventions to delay scheduled coal plant closures.

This is not to suggest a capacity and energy market offers a better pathway. In the Australian context with vast low cost solar and falling battery storage prices, shifting to a capacity market would be a retrograde step. A middle pathway that ostensibly seeks to maintain the energy-only market intact and solve the policymaker problem of confidence in resource adequacy, may be a bespoke policy of 'transient' strategic reserves.

Section 1 noted a strategic reserve comprises a small portfolio of 'out-of-market' plant (Fabra, 2023). This dispatchable capacity is set aside and only relied upon for exceptional circumstances that stretch beyond the reasonable capacity of market participants during episodes of exceptional scarcity (Lo Prete et al., 2025). The pool of plant is contracted typically by way of auction, and financed separately with the size of the portfolio being administratively determined (Fabra, 2018).

The advantage of a strategic reserve policy is that it remunerates targeted plant (Kozlova, et al., 2023), and can be turned on- and off immediately (Neuhoff et al., 2016). Capacity markets on the other hand remunerate all dispatchable plant and become *institutionally integral* to the functioning of a market. Indeed, capacity markets are thought to be subject to a form of *institutional path dependency* (Thelen, 1999) and may therefore be particularly difficult to alter or turn off (Neuhoff et al., 2016). By contrast, errors involved in a strategic reserve will typically be less consequential, and less costly than a centralized capacity market (Neuhoff *et al.*, 2016).

As Neuhoff et al. (2023) explain, market participants in Europe are unlikely to invest in sufficient resilience to maintain generation adequacy and manage fuel security risks due to the uncertainty of financial returns (de Maere d'Aertrycke et al., 2017). This is not reflective of historical NEM investment patterns. As a result, the intention in this research is to deviate from the European strategic reserve by making it transient, specifically to solve the policy problem of lumpy coal plant '*exit before entry*'. The concept here is that the strategic reserve would form a gradually rising level of peaking plant in 'a waiting room' in anticipation of a scheduled coal plant closure. When the waiting room is full of strategic reserve plant, coal plant may close and the strategic reserve released into the energy market (i.e. the post exit environment). This serves two purposes:

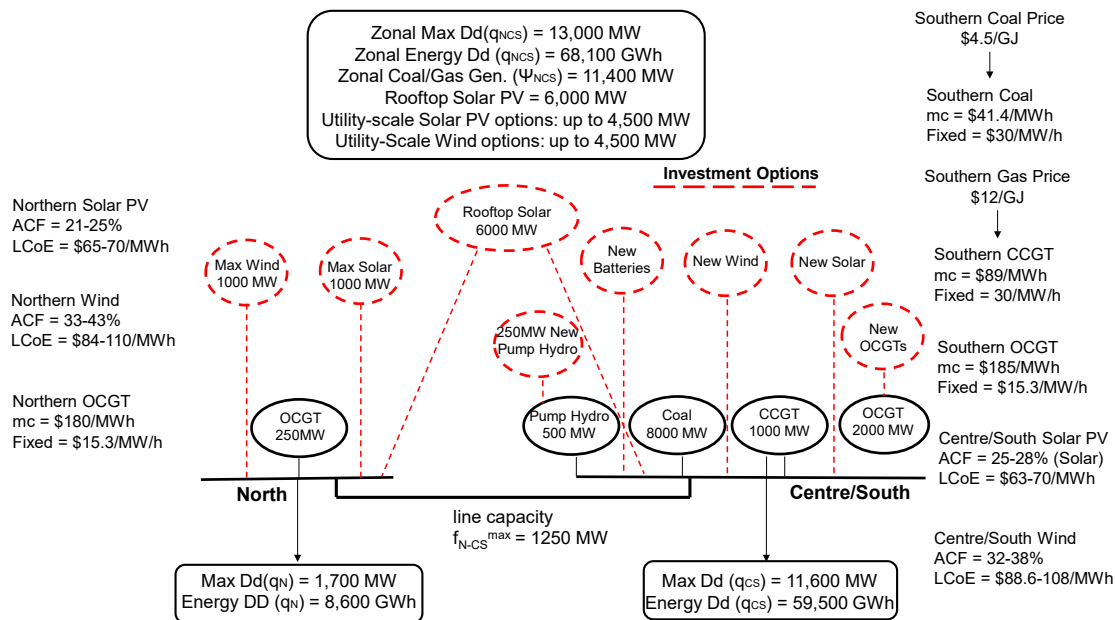
1. Timely establishment of a transient strategic reserve would enable scheduled coal plant closures to proceed by providing jurisdictional governments with confidence that price stability and security of supply is more likely to be maintained in the post exit environment; and
2. The NEM is sufficiently robust to remunerate peaking plant in the post exit environment (see Simshauser, 2026), meaning there is no need to persist with ongoing consumer-funded strategic reserve payments (fully or partially). This limits the risk of an over-procurement problem.

4. Models and Data

In this article, various scenarios of a NEM region are used to illustrate the functioning of the market with/without a transient strategic reserve to manage the dynamics of exit before entry. For this purpose, NEMESYS is used which is a dynamic partial equilibrium electricity market model with half-hourly resolution and security-constrained unit commitment. Price formation within the model is based on the NEM's uniform, first-price auction clearing mechanism and the generation fleet is co-optimised under conditions of perfect competition. NEMESYS model logic appears in Appendix I.

Market conditions and scenarios modelled reflect the prevailing policy challenge of scheduled coal plant closures. Entry, exit and unit commitment occurs across a lossless two-zone network setup (i.e. North Queensland and Centre-South Queensland). The model setup, and all technology input costs and prices, are illustrated in Fig.3.

Figure 2: NEMESYS Model Setup



To summarise the model setup, Queensland aggregate final electricity demand is 13GW // 68,100GWh with ~14% of this supplied behind-the-meter (i.e. rooftop solar PV). The grid-connected supply-side comprises of 8GW of aging coal plant, 3GW of gas turbines, 500MW of pumped hydro, 11GW of renewables (including 7GW of rooftop solar) and a further 4GW of committed utility-scale wind and solar entrants. The period being analysed reflects the approximate circumstances facing the NEM's Queensland region over a five- to seven-year period (nominally from 2026-2032). The market commences in a state of relative, but temporal, equilibrium.

At a certain level, the concept of a transient strategic reserve barely warrants a modelling exercise. Intuitively, if there are genuine concerns over exit before entry then jurisdictional governments – held accountable for a reliable and affordable electricity supply – will drift towards some form of policy intervention in the presence of material supply-side shocks or discontinuity. Indeed, given the political economy of electricity tariffs and of security of supply, governments face very strong incentives to intervene under predictable system stress conditions. Yet in the absence of an explicit transient strategic reserve policy, the dominant policy for governments facing volatile electricity market conditions and risks to the reliability of supply is to intervene and delay scheduled coal plant closures. As modelling later demonstrates, this is certainly an effective option in the short run. Consequently, where a modelling exercise is useful is to examine how policy might be better orchestrated under these conditions, and to quantify costs and risks faced by:

1. Consumers vis-à-vis premature exit and elevated prices on the one hand, versus the incremental costs of a transient strategic reserve on the other; and
2. Investors regarding the predictable financial implications of government interventions relating to scheduled coal plant closure delays (i.e. short run losses for new entrant plant commitments ‘caught out’ by a closure delay).

5. Model Results

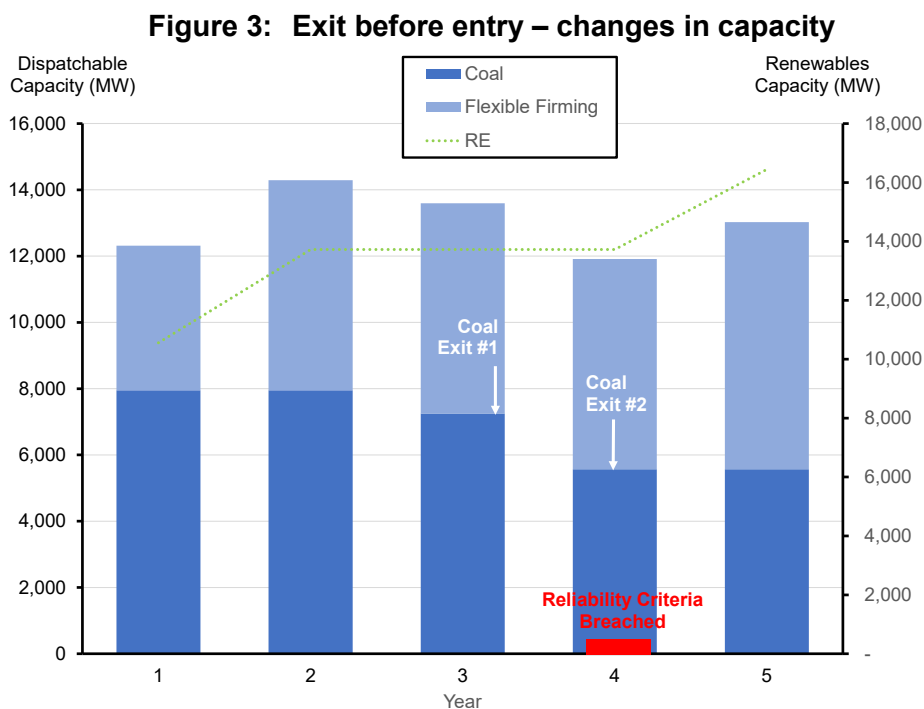
While commencing in equilibrium, the aging coal fleet in Australia’s NEM requires replacement. Non-committed new entrant renewables and dispatchable plant face entry frictions with respect to a perceived risk of coal closure delays. To examine the logical bookend of plausible market outcomes, the following model scenarios in the NEM’s Queensland region are examined:

1. Scenario 1: examines the problem of *exit before entry* – with exit involving almost 25% (2.4GW) of the incumbent coal fleet across two tranches in quick succession. In theory, we should anticipate elevated spot prices and potential breaches of the NEM’s reliability criteria. To be clear, the political economy of such a scenario is intractable, but analysing ‘exit before entry’ provides a form of *stress-tested benchmark*.
2. Scenario 2: examines pre-emptive government intervention via *accelerating the entry of intermittent renewables* (without dispatchable plant) through the use of CfDs. Here we should anticipate merit order effects and a lowering of prices, with a reduced (but not eliminated) risk of potential breaches of the NEM’s reliability criteria.
3. Scenario 3: examines pre-emptive government intervention via a *delay to a scheduled coal plant closure*. Such a scenario should result in lower spot prices, the shift of any risk of reliability breaches to later periods, and sizeable losses incurred by all incumbent plant (or PPA counterparties). And finally,
4. Scenario 4: examines a pre-emptive policy of *transient strategic reserves* to ensure coal closure schedules can be maintained. In theory, we would expect more balanced outcomes in both the spot market and risks to reliability of supply, but with the obvious downside of additional cost added into the system (i.e. the cost of adding the transient strategic reserve).

5.1 Scenario 1 and the messy transition: *exit before entry*

Fig.4 provides an overview of capacity dynamics in the NEM’s Queensland region with aggregate coal plant represented by the dark blue bars, flexible firming capacity by light blue bars (LHS axis), and renewable plant capacity by the green line series (renewables measured on the RHS axis).

Note that two coal plants of 2.4GW capacity exit the market in Years 3 and 4. At this point, the coal fleet contracts from 8GW to 5.6GW. Approximately 3GW of flexible plant capacity progressively enters comprising 1.75 GW of short duration batteries and 0.25GW of pumped hydro in Year 4, and 1GW of GTs in Year 5 (i.e. the post exit environment). Renewable plant commences at 10.6GW in Year 1 and rises to 17GW but visibly stalls in the middle years (Yrs 2-4). Stalled renewables and late entry of GTs in Year 5 results in unserved load in Year 4, breaching the NEM's reliability criteria (i.e. no more than 0.002% lost load).

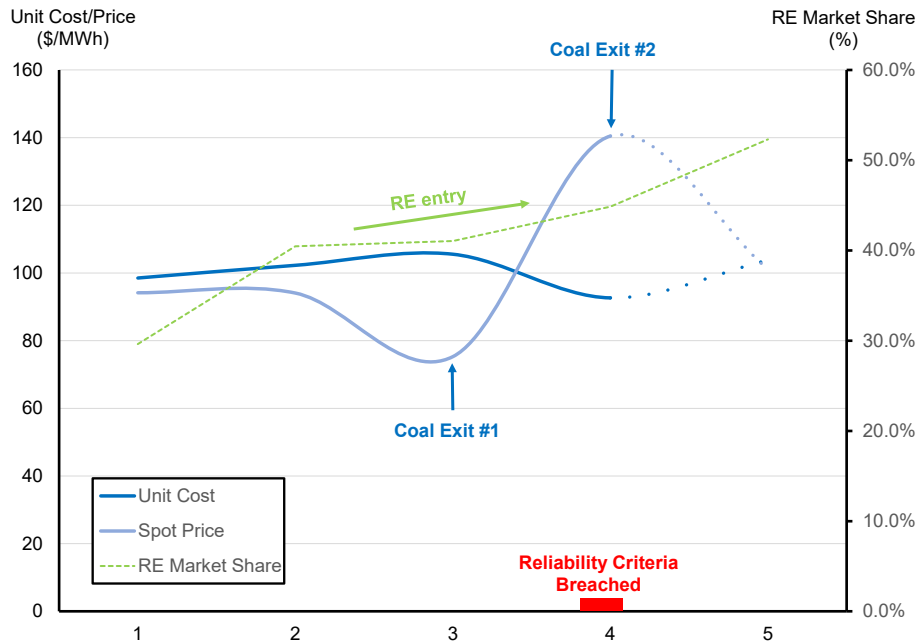


The resulting annual average spot prices that flow from this scenario is illustrated in Fig.5. They exhibit two distinct dynamics vis-à-vis costs and prices, as follows:

1. During the initial years with the coal fleet held constant and renewables entering, merit order effects dominate. Power prices fall from ~\$95 in Year 1 to ~\$75/MWh in Year 3.
2. Coal plants close in Years 3-4. The first coal closure is comfortably accommodated by the combined entry of renewables (Year 2), pumped hydro and batteries (Year 3). Closure of the first coal plant, and replacement with a flexible storage fleet, has the effect of reducing renewable curtailment rates in Year 3 (cf. Year 2). This is because the aggregate coal fleet's minimum stable load reduces following exit of the first coal plant.
3. The second coal plant closure in Year 4 is not matched with requisite flexible plant capacity in a timely manner and therefore supply-demand imbalances breach a threshold, sending spot prices from ~\$75 to ~\$140/MWh (see light blue line series in Fig.5) – a virtual doubling in the wholesale market, as occurred with the Hazelwood coal plant exit in Victoria in 2017 (see Nelson et al., 2022) Nelson et al., 2022).
4. From a system cost perspective, unit costs of the generation fleet behave in the exact opposite manner (see dark blue line series, Fig.5). As renewables and pumped hydro enter in Years 2-

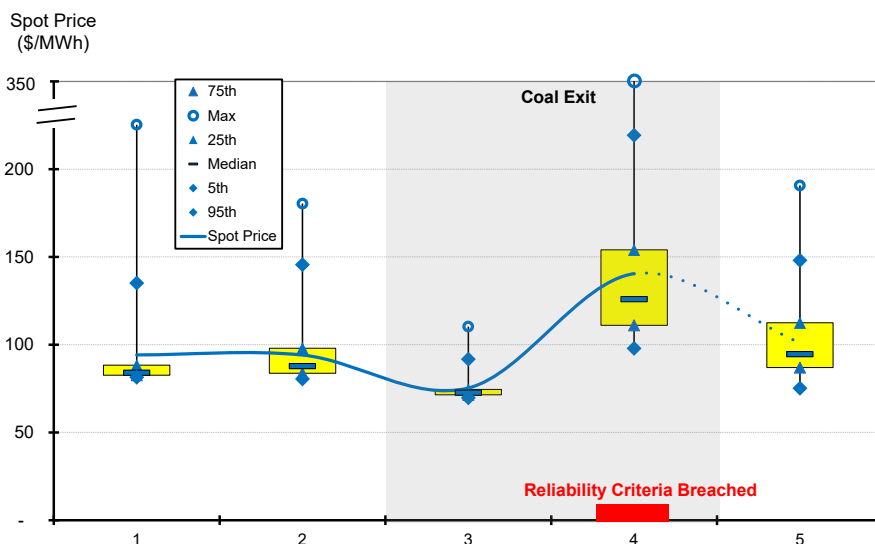
- 3, the average unit cost of the aggregate generation fleet rises, creating a sizable gap between spot prices (~\$75/MWh) and unit costs (~\$106/MWh). Market-exposed generators and holders of PPAs face sizable losses.
5. Exit of coal plants in Years 3-4 result in unit costs falling, before rising once again in Year 5 with the addition of new renewables and the GT fleet. Spot prices and unit costs largely re-balance at this point.

Figure 4: Exit before entry – unit costs and average spot prices



The NEMESYS Model was used to undertake 100 stochastic iterations of this scenario, and the distribution of spot prices are illustrated in the box plot in Fig.6. Spot prices of the 1st iteration (per Fig.5) are illustrated by the line series, whereas the box plot identifies the risk to consumers of this scenario – particularly in Year 4. The 25th-75th percentile area (yellow shaded boxes) is elevated with a particularly long tail risk extending beyond \$300/MWh.

Figure 5: Exit before entry - spot price distribution



In Australia's NEM, the consumer base is tolerant of load shedding events arising from extreme weather conditions (e.g. cyclones, floods, bushfires) – all of which can be expected to occur regularly on Australia's east coast. However, the political economy of load shedding and surging spot prices – underpinned by an apparent episode of poor planning – is problematic. Media coverage will induce a very different response from the voting public. It is for this reason that risks of an *exit before entry* scenario have led to government intervention and the rise of *quasi-closure commitments*.

5.2 Scenario 2: The pre-emptive underwriting of renewables via CfDs

What if a jurisdictional government sought to accelerate the entry of wind and solar through CfDs given sufficient lead-time for implementation. Would this make a difference to our exit scenario in Figs.4-6 vis-à-vis high prices and the reliability of supply breach? In Scenario 2, entry of renewables is brought forward by one year to simulate the policy with all other parameters otherwise held constant. Results appear in Figs.7-9.

The first point to note in Fig.7 is that the primary effect of pre-emptive CfDs is a sharp increase in renewable market share, from ~40 to 50+% in Year 4 (see green line series, RHS axis). Yet this does not eliminate the breach of the NEM's reliability criteria. Additional renewables reduce, but does not eliminate, a breach of the reliability criteria. Conversely, bringing forward renewables has a favourable impact on spot price levels and volatility in Year 4 (see Fig.8). Indeed, as results from 100 stochastic iterations of this scenario demonstrate in Fig.9, average prices reduce by almost \$40/MWh compared to the counterfactual, with a material tightening of the distribution of prices.

However, power system reliability remains in breach of the reliability standard because of VRE intermittency, meaning a resource adequacy problem persists. This leads us to examine the impact of delaying a scheduled coal plant closure, in Section 5.3.

Figure 6: Pre-emptive renewable CfDs – changes in capacity

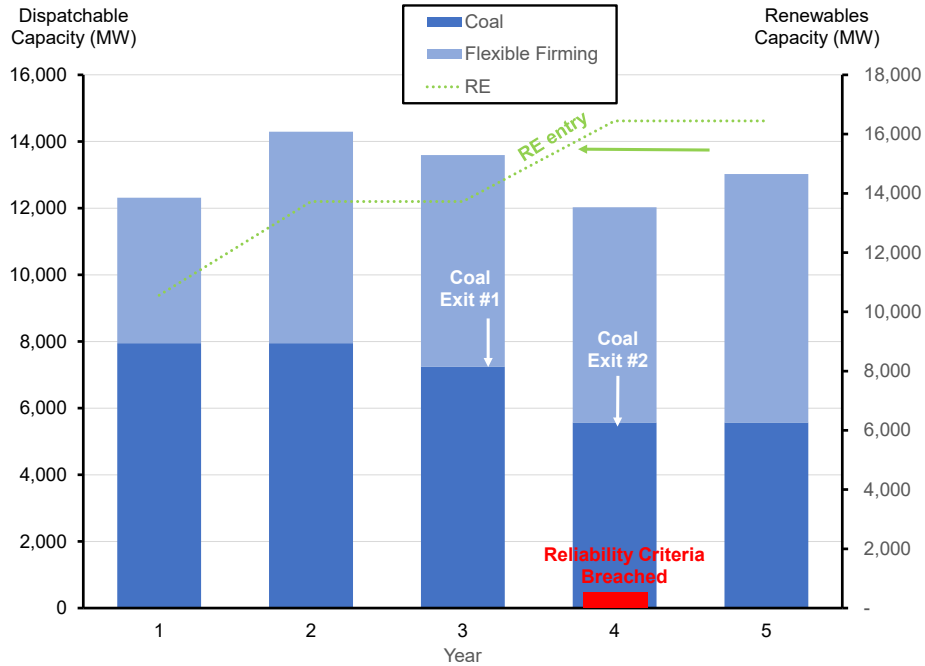


Figure 7: Pre-emptive renewable CfDs – unit cost and average spot prices

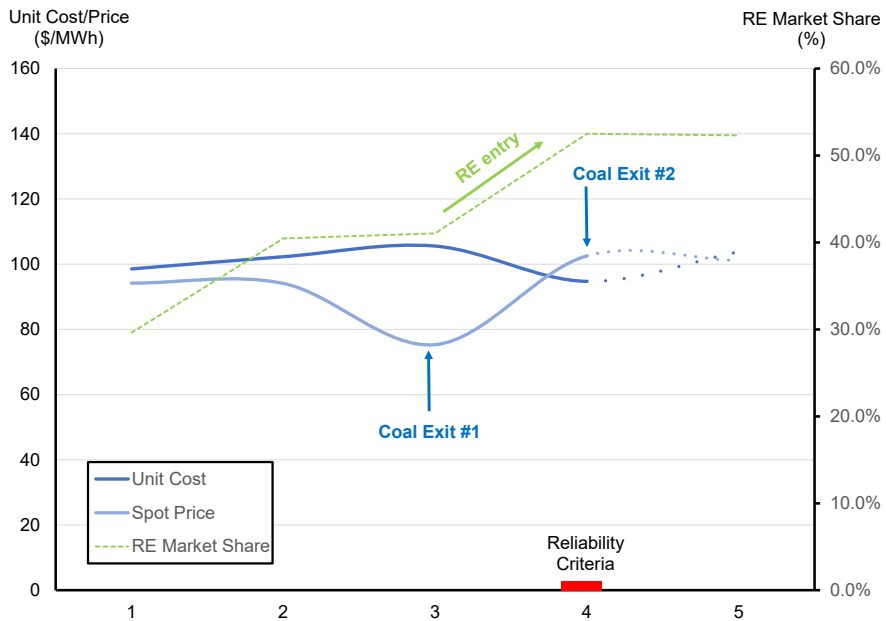
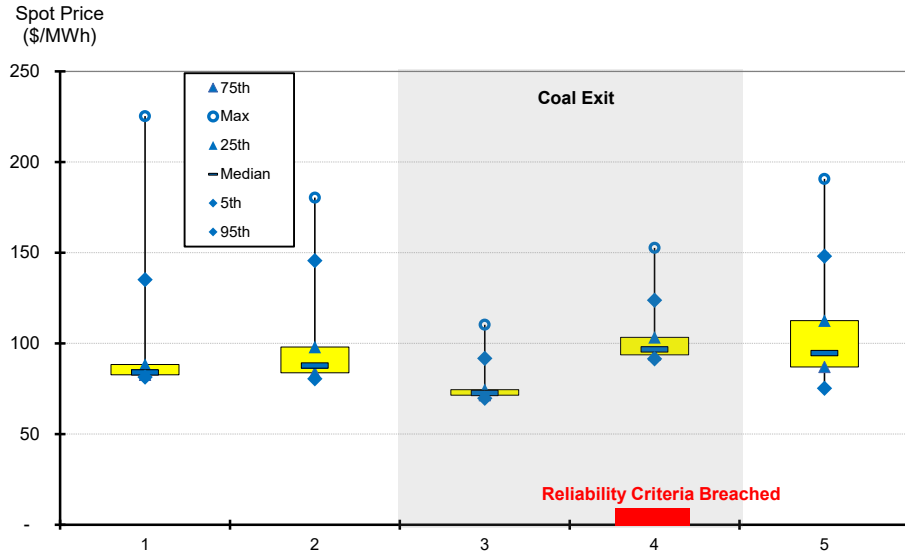


Figure 8: Pre-emptive renewable CfDs – spot price distribution



5.3 Scenario 3 and the delay to a scheduled coal plant closure

Presented with the outcomes of Scenarios 1 and 2, in a mature debate, a jurisdictional government can hardly ignore the risk of breaches to the reliability criteria, nor the tail risk identified in the distribution of spot price outcomes in Scenario 1. Given the political economy of supply reliability and price stability, if no alternate option exists, then delaying a scheduled coal plant closure will axiomatically emerge as the politically dominant policy solution, with the intention being to enable sufficient time for replacement capacity to emerge. Fig.10-12 examine the outcomes of a delay to the scheduled coal plant closure, and confirms lower prices, and no reliability breach.

Figure 9: Scheduled coal closure delay – changes in capacity

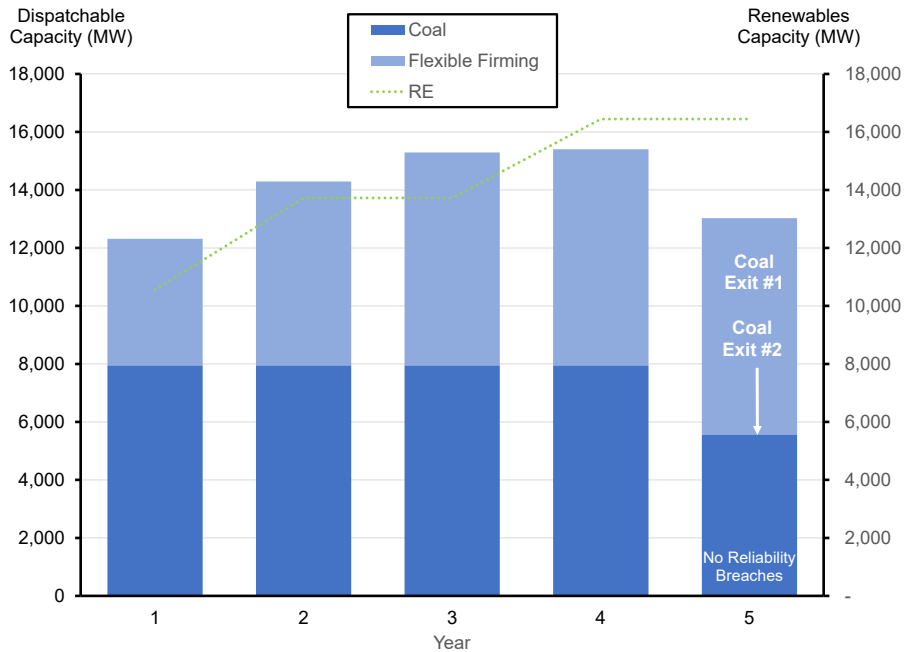


Fig.11 and Fig.12 reveal spot prices compress under all plausible contingencies during Years 3-4 before reverting to equilibrium in Year 5. However, this required an intervention whereby government

extended the life of coal plant #1 and coal plant #2 by 'x years' – with 'x' deliberately undefined, thus introducing a new dimension to the problem. If government intervenes and announces a delay of 2 years, how can the market be certain that 'x = 2'? In short, the entry task facing requisite new entrants has just been made materially harder, evidenced by sizeable economic losses across the fleet of incumbent coal, gas, hydro, battery and renewable generators will be sizable in each of Years 3-4 (i.e. the losses are equivalent to c.25% of the aggregate generation fleet average total cost).

Figure 10: Scheduled coal closure delay – unit cost and average spot prices

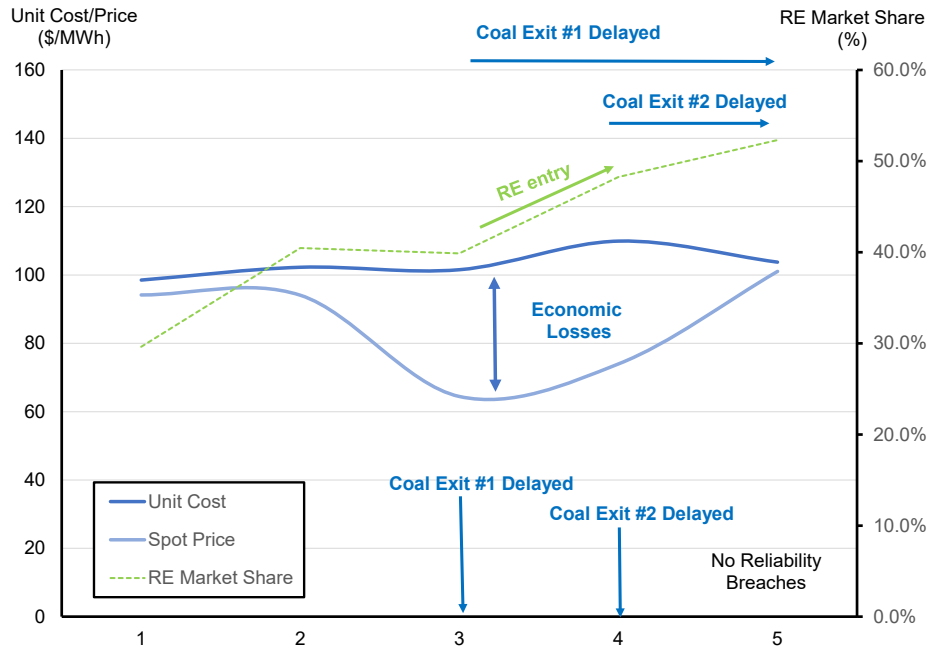
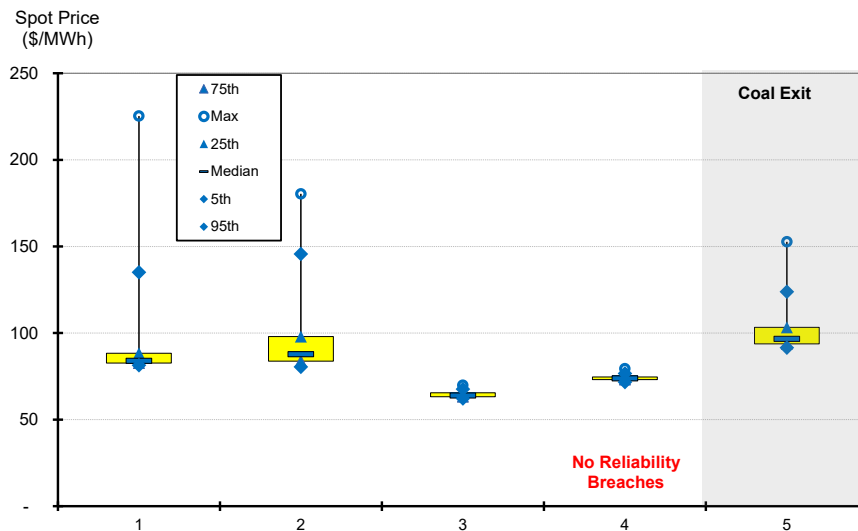


Figure 11: Delay to scheduled closures – distribution of spot prices



If 'x' becomes 4 years rather than 2, economic losses of any new entrant plant would compound those that prevail in the pre-exit environment of Years 3-4. Thus is the circular reasoning of the *entry-exit problem*, and the motivation for a pre-emptive, transient strategic reserve.

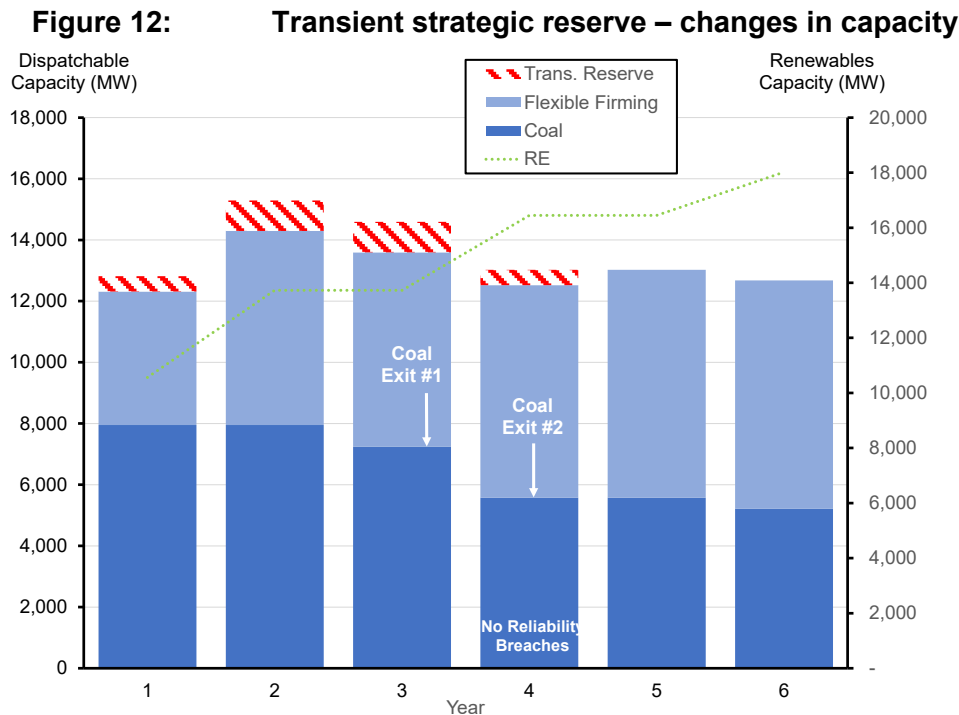
5.4 Scenario 4: Transient Strategic Reserve

Clearly, each of Scenarios 1-3 are problematic either in the short- or medium run. Ultimately, no government can preside over probable risks to security of supply when options to intervene exist (i.e. delay a scheduled coal plant closure and avoid a near-term political event). If the coal fleet was in good operating condition and mid-way through its useful life, this may be sustainable. But Figs. 1a-1b confirm that (1) as coal plant ages, outage rates rise, and (2) the MW-weighted average age of the remaining coal fleet is 39 years, meaning life extensions will reach a natural speed limit.

Compounding matters, intervention by way of delays to scheduled coal plant closures may be interpreted by investors as erratic or capricious policy, and a pattern of intervention to scheduled closures risks creating a spiral of delay, followed by stalled entry, followed by further delay.

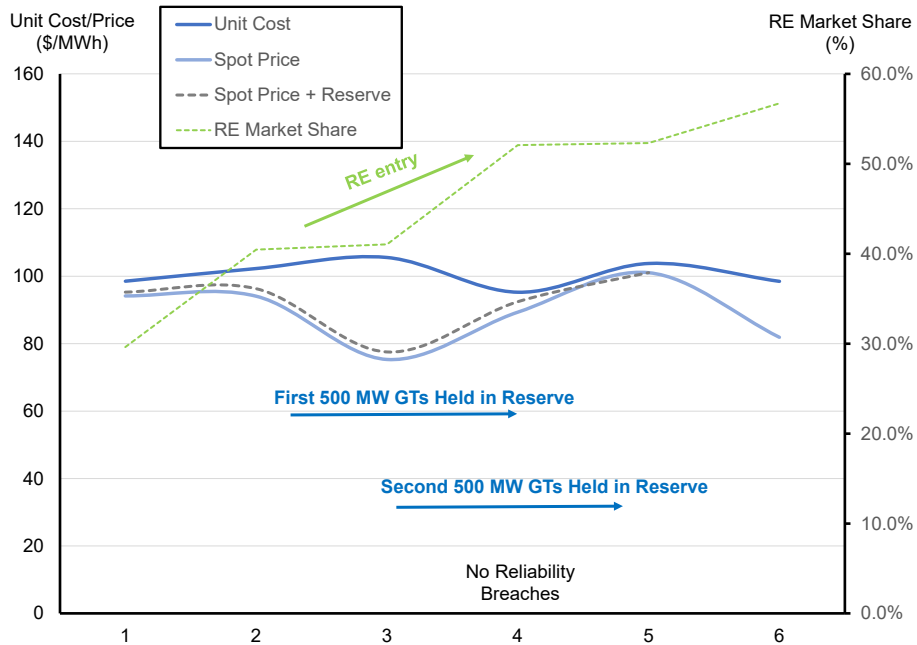
In a capacity-constrained system, one option to break this apparent cycle is a transient strategic reserve. Here, a stable post-exit environment is reverse engineered by deliberately orchestrating a fleet of reserve capacity generators – in this instance Open Cycle GTs. But this comes at a cost.

Figs. 13-15 illustrate the results of this scenario. Pre-emptive entry of GTs commences gradually from Year T-3 relative to the coal closure events. The size of the strategic reserve is of course the subject of forecast error vis-à-vis timing and quantity, but for now we shall set aside such errors. Build-up of the pre-emptive transient strategic reserve or '*waiting room*' is illustrated in Fig. 13 by the red bar series. Exit from the waiting room (signalled by the reduction in the red bar series, and commensurate rise in the flexible firming fleet) coincides with coal plant exit.



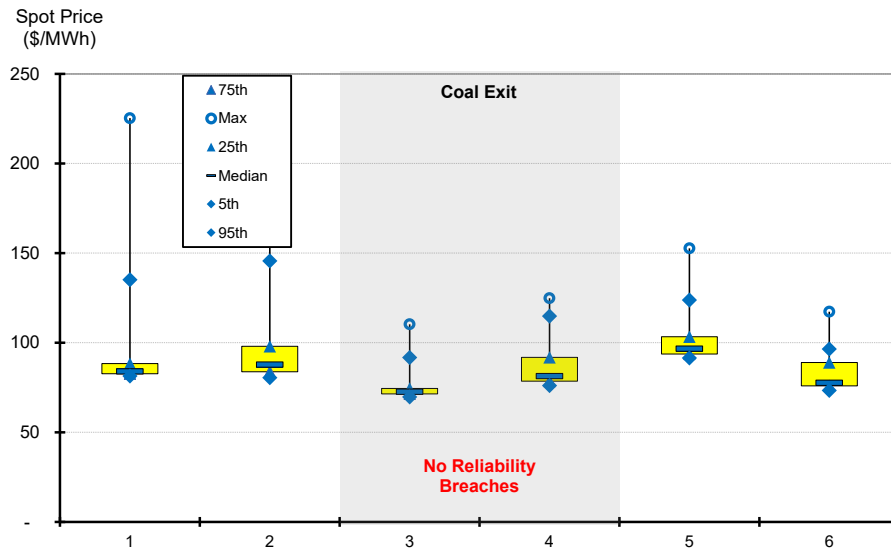
How this altered fleet of generators performs in the market is illustrated in Fig. 14 and there are two key results. First, the gap between generator costs and prices reduces very significantly. Second, the cost of the transient strategic reserve, which has been added to the spot price and illustrated by the dashed black line series (Fig. 14) is comparatively trivial. Specifically, spot prices average ~\$78-100/MWh over the six-year window, and the transient reserve cost added to this is less than \$2/MWh.

Figure 13: Transient strategic reserve – unit costs and spot prices



Finally, note in Fig.15 that the distribution of spot prices is not riskless. That is, the strategic reserve does not eliminate the possibility of elevated average annual spot prices. But the distribution is significantly reduced by comparison to alternate scenarios – and – for investors in all other technologies (i.e. wind, solar batteries, pumped hydro), the prospect of scheduled coal plant closures maintaining their exit schedule has been heightened, which can only be a positive for new entrant investor sentiment.

Figure 14: Transient strategic reserve – distribution of spot prices



Crucially, a transient strategic reserve does not institutionalise administrative decision-making. The transient reserve is only required in anticipation of a scheduled coal plant closure under conditions of inadequate confidence in the post entry environment. Furthermore, when coal plant closes, the transient reserve may be closed.

5.5 Modelling sensitivities and limitations

The purpose of analysing the four scenarios, and the use of ~100 iterations per scenario, was designed to provide a level of inherent sensitivity testing. However, each iteration was ultimately reliant on a set of fixed cost inputs by technology. Furthermore, GT entry was assumed to be frictionless and perfect. The main sensitivity and limitation to the transient strategic reserve result outlined in Section 5.4 comes down to technology selection given risks to frictionless entry, and the consequential costs of alternatives. In the real world, the market for gas turbines currently involves lengthy lead order times (i.e. now stretching to 3-5 years), and sharply rising OEM GT pricing.

If a transient reserve needed to be activated quickly, GTs may not be a viable option. One alternative may involve long duration batteries (i.e. 6-8h). Switching from GTs to a battery would reduce lead order times but come at greater cost than GTs – and would not resolve an inherent energy constraint of this was of concern (i.e. batteries shift energy, GTs produce energy). Given current costs and prices, sensitivity modelling of using batteries would increase the estimated cost of the transient strategic reserve (i.e. from ~\$2/MWh) at a roughly 3x multiple. Additionally, the strategic reserve may start to lose its ‘transient’ character – noting in the current market environment, 2-4h batteries are economic, whereas 6-8h are not.

6. Policy Implications

Given the political economy of electricity prices and a reliable supply, any adverse ex ante forecast involving a scheduled coal plant closure is likely to result in a predictable policy response – delay the scheduled closure. Governments face particularly strong incentives to intervene. Indeed, it is likely to be the dominant political response given development, environmental and commissioning lags facing plant entry under ideal conditions let alone a looming coal plant closure (Clapin and Longden, 2024).

Government interventions to delay a scheduled coal plant closure can then be expected to adversely impact forward prices (Nelson et al., 2022). This creates an entry fiction for new entrants, the very entrants required to enable a scheduled closure to proceed, thus creating a circular reasoning. Under these conditions, power system need for new entrant plant presents much stronger than practical investment cases for new plant, due to the asymmetric consequence of closure delays on near term returns.

A broad-scale shift from the energy-only market design to a traditional capacity and energy market is unlikely to be the most efficient means by which to solve the circularity of delays to scheduled coal plant closures (i.e. *quasi-closure commitments*) outlined in this article. In contrast, the concept of a pre-emptive transient strategic reserve is intended to be a surgical response to maintain power system reliability by providing an entry bridge for dispatchable generation where an imbalance exists between power system need and the investment case. Ultimately, replacement capacity *must enter ahead* of anticipated closures, and ideally, with a ramping scale. Recent NEM experience has shown more serious modes of failure occurring at aging coal plants – a not unexpected outcome. A transient reserve can be deployed pre-emptively and divisibly to manage such risks at relatively low cost.

For investors, uncertainty over coal closure timing may make final investment decisions for new firming capacity challenging (Simshauser, 2026). Global supply chain constraints and grid connection requirements increase the risk of entry-exit timing mismatches. Forecasting exit dates appears to have the added complexity of political decisions, a notoriously difficult prospect for investors to navigate (Offer, 2018, Newbery et al., 2020). Conversely, as new renewable capacity progressively enters, exiting coal plant may begin to experience financial distress whilst still being needed for system security purposes.

The intent of the transient strategic reserve or ‘waiting room’ is to provide certainty for jurisdictional governments, consumers and investors by establishing a physical reserve of new strategic capacity ahead of time. Auctions for requisite new capacity may be held with new dispatchable resources underwritten for at least the period *prior* to coal plant closures.⁶

Within the limits of development lags and supply chain constraints, a waiting room policy can be rapidly deployed. And above all, the policy is both surgical and optional. Jurisdictional governments could decide to use it (or not), and determine the conditionalities to address social, locational (i.e. regional) or other relevant considerations.

Implementation requires jurisdictional governments, the market operator and market participants to identify reliability risk scenarios relevant to transitional periods. These should include all impacts of a large coal plant closure including structural shortages which may arise in forward markets immediately prior and in the post-exit environment, extreme weather risks, technical failures, or other tail-risk events that are difficult to forecast or insure against. The transient reserve auction should pre-emptively seek to pull forward the appropriate resource mix (i.e. invariably, peaking and reserve plant) required to insure against extreme shocks whilst matching jurisdictional reliability and risk appetite.

Successful bidders to a transient reserve auction may be entitled to (at least) the period of entry through to a scheduled coal plant closure, which in this article was nominally a phase in period of T-3 years. This approach may give investors the confidence during the timeframe characterised by heightened uncertainty. During these T-3 to T-1 years, new dispatchable assets would operate within the reserve framework, acting as an out-of-market physical reliability hedge while minimising market distortion (i.e. a non-price setting function). Early entry may also offset the need for expensive emergency reserves typically (called on by the market operator) during the waiting room period.

As the waiting room continues to fill, from Years T-3, T-2 and T-1, transient reserve participants may access a revenue floor, which in theory could be orchestrated to enable forward-contracting at the same time exiting coal units progressively withdraw from the forward market with some adjustments. Without the possibility of this intervention under conditions of lumpy exit, forward market liquidity may fall to critical levels, with adverse consequences for consumer pricing.

Once a scheduled coal plant closure occurs, plant capacity in the strategic reserve would exit the waiting room and transition into the energy market. At this point, underwriting would end unless a scheduled coal unit’s closure is delayed (e.g. for tangential security-related reasons), in which case underwriting would continue. Where coal units retire earlier than expected, reserve resources may need to enter the market ahead of schedule.

A complementary mechanism may also be designed to manage coal plant closures themselves. Around 14 GW of coal generation (i.e. two-thirds of the NEM’s remaining coal fleet) could retire within the next decade. To manage committed closures, governments could provide targeted, time-limited, support guaranteeing coal plants to undertake necessary maintenance and continue operating reliably until the waiting room is adequately established. The objective would be to maintain security and resilience during cross-over periods while avoiding prolonged operation of coal assets.

Cost recovery for the mechanism may occur through various forms such as an adjustment to distribution-level retail tariffs. This may ideally be undertaken by increasing the daily fixed charge applied to retail customers. By way of context and simple example, funding the 500MW of transient

⁶ The proposed mechanism would differ from the NEM’s Reliability and Emergency Reserve Trader or ‘RERT’ provisions (and other Jurisdictional Reserves) by bringing forward replacement capacity that will ultimately reduce consumer costs (longer duration batteries, gas turbines etc.) rather than only funding high-cost reserves.

reserves in Queensland presented in this article would require raising the daily fixed charge to residential customers by approximately three cents per day, increasing the current \$0.97 per day fixed rate to ~\$1.00 per day. This translates to an additional \$12 per household annually, and roughly \$30 per year for small to medium-sized businesses.

7. Concluding remarks

Australia's NEM faces amongst the world's most complex decarbonisation tasks given the historic dominance of coal fired generation fleet. Historic experiences with large coal plant exit have not always tracked well. More recently, scheduled coal plant closures have been delayed in the presence of an array of entry frictions facing new investments. Modelling in this article has highlighted that unmanaged coal closures on the one hand, or repeated government interventions to delay scheduled coal plant closures on the other, may produce material risks for consumers in the NEM either in the short run or long run, respectively.

The starting premise of this research is that the fundamentals of the energy-only market design are well suited to the energy transition. But the practical evidence from Australia's NEM is that the scale of coal closures (i.e. lumpy exit) and the ability of the market to coordinate the timely and requisite mix of new entrant renewables and dispatchable plant has fallen short of the risk appetite of policymakers. The dominant policy response, given the political economy of electricity prices, is to delay scheduled coal plant closures. Delayed closures induces further delays to entry, with policymakers inadvertently amplifying the problem they are seeking to solve.

A transient strategic reserve or 'waiting room' offers a surgical policy solution to the circularity of the problem. By temporarily underwriting a portfolio of dispatchable resources ahead of scheduled coal plant closures, governments can maintain overall system stability during periods of heightened uncertainty. Such a reserve may also enable requisite renewable and storage projects (i.e. outside of the reserve) to proceed to financial close with greater confidence about the timing of coal plant closures.

The modelling highlighted transient reserves may reduce price volatility and reliability risks at comparatively low cost, without institutionalising a permanent capacity market, or adversely affecting the clarity of the price signal that comes with an energy-only market design. Ultimately, the waiting room provides a practical pathway to deliver an *entry before exit outcome* (cf. exit before entry) in a power system facing a sequence of very large coal plant retirements. A transient strategic reserve should therefore be capable of supporting a more orderly, efficient and durable energy transition in Australia's NEM, thus optimising the extent of administrative decision making.

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Appendix I: NEMESYS Model Logic

Let H be the ordered set of all half-hourly trading intervals.

$$i \in \{1 \dots |H|\} \wedge h^i \in H, \quad (1)$$

Let \mathcal{N} be the ordered set of nodes within the regional power system and let $|\mathcal{N}|$ be the total number of nodes in the set. Let η_n be node n where:

$$n \in (1..|\mathcal{N}|) \wedge \eta_n \in \mathcal{N}, \quad (2)$$

Aggregate final (grid-supplied) demand at each node comprises residential, commercial, and industrial consumer segments. Let E be the set of all electricity consumer loads in the model.

$$w \in \{1 \dots |E|\} \wedge e_w \in E, \quad (3)$$

Let $V_w(q)$ be the valuation that consumer segment w is willing to pay for quantity q MWh of electricity. Let $q_{w,n}^i$ be the metered quantity consumed by customer segment w in each trading interval i at node n expressed in Megawatt hours (MWh). In all scenarios and iterations, aggregate final demand is

modelled as a strictly decreasing and linear function with own-price elasticity of -0.08. This elasticity estimate is consistent with Burke and Abayasekara (2018), Australian Energy Market Operator (AEMO) 2019 and Sergici et al., (2020) and is applied by reference to average wholesale prices p during solar periods, evening peak, and overnight periods against the equivalent 'base case' reference prices.

Generation investment and spot market trading are assumed to be profit maximising in a perfectly competitive market with all firms as price takers, thus yielding welfare maximising outcomes within the technical constraints outlined below. Let Ψ_n be the ordered set of generators at node n .

$$g \in \{1..|\Psi_n|\} \wedge \psi_{ng} \in \Psi_n, \quad (4)$$

Conventional plants are subject to a regime of both scheduled and forced outages. Planned outages are simulated at the rate of 35 days every 4th year, while forced outages are the subject of random simulations equivalent to ~3-6% per annum. Let $F(n, g, i)$ be the availability of each plant ψ_{ng} in each period i . Annual generation fleet availability is therefore:

$$\sum_{g=0}^{|\Psi_n|} F(n, g, i) \forall \eta_n, \quad (5)$$

Conventional plant face binding capacity limits and minimum load constraints. Let $\hat{g}_{\psi_{ng}}$ be the maximum productive capacity of generator ψ_{ng} at node n and let $\check{g}_{\psi_{ng}}$ be the minimum stable load of generator ψ_n . Plant marginal running costs are given by mc_{ng} . Let $g_{\psi_{ng}^i}$ be generation dispatched (and metered) at node n by generator ψ_n in each trading interval i expressed in MWh. Let d_n^i be the cleared quantity of electricity delivered in trading interval i at node n expressed in MWh.

Pumped hydro plant form part of the incumbent plant stock and are a potential entrant. The pumped hydro fleet operates with imperfect foresight, using 'demand triggers' (MW) as a proxy for *water opportunity cost* as is frequently employed by long-duration storage assets. Pumped hydro plan operate as a single unit in each node. Define ρ_n^i as the *residual demand* in node n , being demand plus net interconnector flows (imports) into node n (defined below) minus available variable renewable generation, defined as follows:

$$\rho_n^i = \sum_w q_{w,n}^i - \sum_{\bar{g}} F(n, \bar{g}, i) - \sum_{\Omega_A} f_{An}^i, \quad (6)$$

where the sum over generating units is over zero marginal running cost renewable generators \bar{g} . Pumped hydro production is modelled to increase linearly from zero to nameplate capacity over a set range. Let $\xi_{+,0,n}$ and $\xi_{+,full,n}$ (subject to additional constraints set out below) be the production range. This structure avoids sharp discontinuities in dispatch for small changes in demand. Similarly, let $\xi_{-,0}$ and $\xi_{-,full}$ be the demand range for charging (pumping) behaviour. These levels are set empirically to match typical operational behaviours, specifically at the 40th to 50th percentiles (charging) and 65th to 70th percentile of residual demand (generating).

Let SOC_n^i be the available stored energy for pumped hydro in region n , constrained by the nameplate storage capacity via $0 \leq SOC_n^i \leq SOC_n^{max}$, and satisfying the following energy balance timeseries:

$$SOC_n^{i+1} = SOC_n^i - g_{\psi_{n,ph}^i} \tau \times \{\gamma_n \text{ if } g_{\psi_{n,ph}^i} < 0\} \quad (7)$$

where $\psi_{n,ph} \in \Psi_n$, τ is the simulation timestep, and γ_n is the average round-trip efficiency of the pumped hydro fleet at that node. Initial conditions are $SOC_n^0 = SOC_n^{max}$. Finally, pumped hydro charging load is constrained to be no more than the available renewable energy and coal capacity in each dispatch interval (i.e., the pumps will not charge off gas units). Pumping load in each period is therefore given by:

$$g_{\psi_{n,ph}^i}^{(pumping)} = (-1) \times \text{minimum of } \begin{cases} \hat{g}_{\psi_{n,ph}} \times \min \left(1, \max \left(0, \frac{\rho_n^i - \xi_{-,full,n}}{\xi_{-,0,n} - \xi_{-,full,n}} \right) \right) \\ (SOC_n^{max} - SOC_n^i) / \tau / \gamma_n \\ \left(\sum_{g \in \psi_{n,coal}^i} \hat{g}_{\psi_{ng}} \right) - \rho_n \end{cases} \quad (8)$$

For generation, output is similarly constrained to available SOC_n^i and the residual demand net minimum stable operating levels of coal units.

$$g_{\psi_{n,ph}^i}^{(generating)} = \text{minimum of } \begin{cases} \hat{g}_{\psi_{n,ph}} \times \min \left(1, \max \left(0, \frac{d_n^i - \xi_{+,0,n}}{\xi_{+,full,n} - \xi_{+,0,n}} \right) \right) \\ (SOC_n^i) / \tau \\ \rho_n - \left(\sum_{g \in \psi_{n,coal}^i} \check{g}_{\psi_{ng}} \right) \end{cases} \quad (9)$$

Batteries seek to arbitrage the highest and lowest demand periods on a day based on perfect foresight within the day. Batteries dispatch in the highest dispatchable demand periods and charge in the lowest periods. We assume batteries constrain their activity to one cycle per day, with commercial constraints described below. Given nodal battery $\hat{g}_{\psi_{n,bess}}$ with nameplate energy storage capacity $S_{\psi_{n,bess}}$, for each simulation day D^d , let $\{\delta_n^{d,j}\}$ be the ordered (descending) set of *dispatchable demand* available to batteries defined as residual demand in node n net of either coal minimum load (if batteries can economically displace coal) or coal nameplate capacity (if batteries should preferentially displace gas),

$$\{\delta^{d,j}\} = \text{SortDescending} \left[\rho_n^i - \sum_{g \in \psi_{n,coal}^i} \left[\check{g}_{\psi_{ng}} \text{ or } \hat{g}_{\psi_{ng}} \right] - g_{\psi_{n,phes}^i} \right],$$

$$\rho_n^i \in \{1 \dots |D^d|\} \wedge D^d \subset H. \quad (10)$$

Dropping the superscript d and subscript n for clarity, battery dispatch q^j in each sorted interval is optimised to minimise the number of periods of non-zero dispatch $\{|1 \text{ if } q^j > 0 \text{ else } 0|\}$ subject to constraints that dispatch in each period is less than nameplate capacity $q^j \leq \hat{g}_{\psi_{n,bess}}$, is less than available demand $q^j \leq \delta^j$, and either $\sum_{j \text{ s.t. } q^j > 0} q^j = S_{\psi_{n,bess}}$ or $\{|1 \text{ if } q^j > 0 \text{ else } 0|\} = |D|$ (i.e., the battery has either dispatched its total storage capacity across the day or there was insufficient dispatchable demand to do so).

By default, battery dispatch is constrained to never oppose pumped hydro operations. Symmetric calculations are applied to battery charging, charging in the lowest *dispatchable demand* periods but constrained not to charge off gas, i.e., dispatchable demand is below coal headroom s.t. $\delta^j \leq \sum_{g \in \psi_{n,coal}^i} (\hat{g}_{\psi_{ng}} - \check{g}_{\psi_{ng}})$. Battery dispatch in each day is then remapped to the original indices to obtain the final net dispatch, $g_{\psi_{n,bess}^i}$ (positive for generation, negative for charging).

Let $p_{\psi^i}(q)$ be the uniform clearing price that all dispatched generators receive for generation dispatched or pay during charging, $g_{\psi_n^i}$. Were it not for network constraints, the real-time problem to be solved is in fact a simple one:

$$\min_{q_n^i} \left(\sum_i mc_{\psi_{ng}^i} (g_{\psi_{ng}^i}) q_n^i \right), \quad (11)$$

where

$$\exists \psi_{ng}^i \text{ if } \left(g_{\psi_{ng}^i} \right) \begin{cases} \neq 0, 0 < \check{g}_{\psi_{ng}^i} < g_{\psi_{ng}^i} < \hat{g}_{\psi_{ng}^i} \forall \psi_n \wedge \left[\left(\sum q_{w,n}^i - \sum g_{\psi_{ng}^i} \right) / \sum q_{w,n}^i \right] \not\geq USE, \\ = 0, 0 \end{cases} \quad (12)$$

and

$$\text{If } \left(\sum q_{w,n}^i - \sum g_{\psi_{ng}^i} > 0 \mid USE > 0, p_{\psi^i}(q) = \$17,500/\text{MWh}, \right), \quad (13)$$

Unserved Energy (*USE*) defines the reliability constraint. In the model, the NEM's reliability standard is used with *USE* not to exceed 0.002%. Eq.(12) constrains unit commitment of each generator $g_{\psi_{ng}^i}$ to within their credible operating envelope, and for the market as a whole to operate within the reliability constraint, *USE*. Eq.(13) specifies that any period involving load shedding, market clearing prices default to the Value of Lost Load of \$17,500/MWh, noting this has a tight nexus with the reliability standard.⁷

Let \mathbb{T} be the ordered set of transmission lines t_j linking nodes and let $|\mathbb{T}|$ be the number of transmission lines in the zone.

$$t_j \in (1..|\mathbb{T}|) \wedge t_j \in \mathbb{T}, \quad (14)$$

Let Ω_A and Ω_B be two nodes directly connected to transmission line t_j where

$$\Omega_A \in \mathbb{N}, \wedge \Omega_B \in \mathbb{N} \mid \Omega_A \neq \Omega_B, \quad (15)$$

Let f_{AB} be the flow between the two nodes. Let \hat{f}_j be the maximum allowed flow along transmission line t_j and let \check{f}_j be the maximum reverse flow. The clearing vector of quantities demanded q_n^i or supplied at node n in each trading interval i is given by the sum of flows across all transmission lines starting at that node, less flows across transmission lines ending at that node, if applicable. Net positive quantities at a node are considered to be net supply $g_{\psi_n^i}$ (i. e. $\sum g_{\psi_{ng}^i}$) and negative quantities imply net demand V_n^i :

$$\text{if } q_n^i \begin{cases} \geq 0, g_{\psi_n^i} = q_n^i \\ \leq 0, V_n^i = -q_n^i, \end{cases} \quad (16)$$

⁷ From a power system planning perspective, the overall objective function is to minimise $VoLL \times USE + \sum_{i=1}^n c(G) \mid VoLL \times USE + c(\bar{G}) = 0$, where *VoLL* is the Value of Lost Load, *USE* is Unserved Energy, and where $c(G)$ is the cost generation plant, and $c(\bar{G})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between Reliability and the VoLL. An alternate expression where reliability criteria is based on Loss of Load Expectation is $LoLE = CONE/VoLL$, where CONE is the cost of new entry. For an excellent discussion on the relationship between VoLL and reliability criteria.

Integration of plant costs in the model centres around the transposition of three key variables, Marginal Running Costs $mc_{\psi n}$ Fixed O&M Costs $FOM_{\psi n}$ & where applicable (annualised) new entrant generator Capital Costs, $K_{\psi n}$ and (annualised) new Transmission line Capital Costs, K_{tj} . These parameters are the key variables in the half-hourly power system model and are used extensively to meet the objective function.

Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integrals of demand curves less marginal electricity production costs and any (annualised) generation $K_{\psi n}$ or transmission K_{tj} augmentation costs. The objective function is therefore expressed as:

$$\text{Obj} = \left[\sum_{i=1}^{|H|} \sum_{w=1}^{|E|} \sum_{n=1}^{|N|} \int_{q=0}^{v_n} V_n(q_{n,w}^i) \partial q \right] - \left[\sum_{i=1}^{|H|} \sum_{n=1}^{|N|} \sum_{\psi=1}^{|P|} \int_{q=0}^{g_{\psi n}} mc_{\psi n}(q_{\psi,n}^n) \partial q + FOM_{\psi n} + \sum_{n=1}^{|N|} K_{\psi n} + \sum_{j=1}^{|T|} K_{tj} \right] \quad , \quad (17)$$

S.T

$$0 \leq q_i \leq V_i \wedge \check{f}_j \leq f_i \leq \hat{f}_j \wedge 0 \leq \check{g}_{\psi i} \leq g_{\psi i} \leq \hat{g}_{\psi i}.$$