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Beyond Patchwork Reform

A New Institutional Architecture for the National Electricity Market

The National Electricity Market needs fundamental reform to improve transparency, clarify accountability and help achieve the clean energy transition. This paper provides a pathway to reform, including splitting the Australian Energy Market Operator into two bodies: a market operator and a national grid and system authority.

Report

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Summary

The National Electricity Market (NEM) was designed on the assumption that competitive wholesale trading, supported by private investment and technical regulation, would deliver efficient outcomes across generation, networks and retail. That design relied on scarcity pricing to signal new capacity, on merchant investment to deliver reliability, and on competition to discipline costs. It assumed that environmental constraints could be accommodated within that framework, either through future pricing mechanisms or incremental policy adjustment.

Experience has diverged sharply from those assumptions. The NEM now operates as a hybrid in which reliability and investment are secured not primarily through market signals but through administrative intervention and long-term contracting. Since 2015, successive reliability crises and system security concerns have led to the expansion of reserve procurement, generator directions, minimum generation constraints, administered pricing and, at one point, full market suspension. These measures were introduced as temporary safeguards. In aggregate, they amount to a parallel planning system layered onto the formal market architecture.

Decarbonisation policy follows the same pattern. The original market design did not incorporate a pollution price or a durable carbon constraint. The Renewable Energy Target provided a limited and technology-neutral certificate obligation, but proposals to integrate emissions intensity more systematically were not implemented. With the large-scale target now met and the Safeguard Mechanism playing only a marginal role in electricity, emissions reductions are being driven by a set of overlapping instruments: state renewable energy zones and reverse auctions, small-scale rooftop incentives, Commonwealth underwriting of storage, ISP-led transmission expansion, renewable procurement embedded in retail obligations, and corporate power purchase agreements. Combined with falling renewable and storage costs, these measures have produced substantial emissions reductions. But they operate alongside, rather than through, the core market design.

The central institutional tension is that the Australian Energy Market Operator (AEMO) is required to perform two functions that rest on different principles. As market operator, it must apply dispatch rules neutrally and allow price signals to operate. As system steward, it must intervene to ensure reliability, manage security services, plan transmission expansion and respond to emergencies. When scarcity pricing or volatility becomes politically unacceptable, intervention is inevitable. The result is blurred accountability and an increasing reliance on discretionary fixes.

This paper proposes a structural response. AEMO should be separated into a rule-bound pool market operator and a national grid and system authority with explicit responsibility

for reliability, transmission integration, long-term contracting and emissions integration. Markets would continue to determine short-run dispatch. Investment adequacy, network expansion and decarbonisation would be managed transparently through planning and contracts rather than implicitly through crisis management.

Transmission should be consolidated under public ownership within the grid authority, reflecting its natural monopoly character and the advantages of sovereign financing. Generation should operate under a mixed public–private model, with both merchant and contracted pathways. Distribution reform should focus on aligning allowed returns with actual risk, with public ownership available as a long-term option. Retail competition should be retained where it delivers measurable benefits, but default pricing should be treated as a public obligation linked to system costs.

The objective is not to abandon markets but to assign them a role consistent with their strengths. The NEM has evolved into a planned system operating through a market interface. Formalising that reality would improve transparency, clarify accountability and provide a more stable foundation for the clean energy transition.

Introduction

Australia's National Electricity Market (NEM) was introduced as part of a broader program of market-oriented micro-economic reform in the 1990s. It was hoped, and promised, that reform would lead to lower prices, improved consumer choice and better investment decisions, as well as providing a basis for reducing greenhouse gas emissions.

Three decades on, the central claims of that reform program cannot be sustained. Prices rose rather than fell. Reliability deteriorated, or at least proved inadequate, in critical periods. Regulatory complexity expanded rather than receded. Far from becoming simpler, the institutional architecture of the NEM has accumulated layers of interventions, exceptions and emergency mechanisms designed to compensate for the limitations of the original design. These outcomes were visible before decarbonisation became the dominant operational challenge. The problems are therefore structural rather than transitional.

The transition to a low-emissions electricity system has exposed those structural weaknesses more clearly. Variable renewable energy, distributed generation, declining marginal costs and the need for anticipatory transmission investment do not sit comfortably within an energy-only market model premised on scarcity pricing and merchant investment. Governments have repeatedly demonstrated that they will not tolerate sustained extreme price events or widespread outages, even when these are outcomes of market design. Instead, reliability has been delivered through directions, reserve procurement, administered prices, minimum generation constraints and, in the extreme case, full market suspension. The system now operates as a hybrid of market and plan, while still being described as market-based.

International experience reinforces this diagnosis. Liberalised electricity markets in California, Great Britain, Texas and parts of the European Union have converged toward arrangements in which wholesale markets perform short-run coordination, while investment and reliability are secured through long-term contracts, capacity mechanisms and active system management. The theoretical model of investment financed through scarcity rents has repeatedly collided with political and social constraints. The result has been implicit planning layered onto nominal markets.

This paper argues that Australia should respond explicitly rather than continue improvising. The core institutional problem is that the Australian Energy Market Operator (AEMO) has been asked to perform two incompatible roles: neutral operator of a short-run pool market and steward of system reliability, security and long-term development. These functions obey different logics. Market operation is rule-bound and reactive. System management is forward-looking and discretionary. Combining them has blurred accountability and encouraged continual patching of the original design.

The proposed reform is straightforward. AEMO should be split into two bodies: a pure pool market operator responsible solely for dispatch and settlement under transparent rules, and a national grid and system authority with explicit responsibility for planning, transmission integration, reliability procurement and long-term contracting. This separation would not abandon markets; it would confine them to the tasks they perform well, while making planning functions explicit, accountable and coherent.

The paper is organised as follows. First, it reviews the historical background to NEM reform, examining the intellectual foundations of liberalisation and the empirical record on prices, reliability and productivity. It then situates the Australian experience within international evidence, drawing on cases such as California, Great Britain and Texas to show that the difficulties encountered are not unique but reflect structural features of liberalised electricity markets. This comparative perspective establishes that the tension between market design and political constraints is inherent rather than accidental.

The subsequent sections develop the case for structural separation. They document the cumulative layering of interventions since 2015 and explain why the current hybrid model obscures accountability. The paper then outlines the proposed institutional redesign, detailing the roles of a standalone pool market operator and a national grid and system authority. Separate sections address transmission ownership and planning, generation entry and exit, distribution regulation, and retail competition, explaining how each would function within the revised framework. The concluding section responds to common objections and argues that institutional clarity, rather than further incremental reform, is now the necessary condition for a reliable and decarbonised electricity system.

Historical background

Electricity reform in Australia since the 1990s was driven by the belief that market incentives could outperform integrated public ownership in delivering lower prices, greater reliability and improved efficiency. The creation of the NEM embodied this ambition. Generation, transmission, distribution and retailing were disaggregated, ownership was progressively privatised, and coordination was entrusted to market rules enforced by technical regulators. The expectation was that competition and price signals would substitute for system-wide planning, even in an industry characterised by natural monopoly networks, high capital intensity and long asset lives.

By the mid-2010s, it had become clear that these expectations had not been met. Prices rose rather than fell, reliability deteriorated, and the complexity of regulation expanded rather than receded. These outcomes were not confined to particular jurisdictions or ownership models, but were evident across the NEM as a whole. Nor could they plausibly be attributed to renewable energy, whose growth at that stage was modest. The system was already underperforming relative to its own promises before decarbonisation became a central operational challenge.

Attention initially focused on distribution networks, where privatisation translated directly into higher required rates of return and sharply rising prices. However, a series of failures in the transmission system shifted the debate. The South Australian blackout of September 2016, the Portland smelter outage, and the prolonged Basslink failure exposed the fragility of a grid fragmented across multiple owners, regulators and contractual interfaces. In each case, governments were forced to intervene despite having formally relinquished control. Responsibility for system failure remained public, while control and returns were private.

Claims that privatisation would deliver sustained productivity gains have also failed to withstand scrutiny. Measured labour productivity improvements largely reflected accounting changes and reductions in operational staffing, while total system costs rose. At the same time, managerial, legal, regulatory and marketing overheads expanded markedly. Complex contracting, risk management and compliance functions substituted for the internal coordination that existed under public ownership. The result was not leaner operation, but higher system costs devoted to managing the consequences of fragmentation.

It is also important to note that climate change was not an unforeseen complication. The scientific basis of climate change was well established by the time the NEM was designed, and the need to reduce emissions from electricity generation was widely recognised. Yet the market was constructed as if decarbonisation were at best a peripheral issue. No serious attempt was made to design institutions capable of managing a transition away from fossil

fuel generation, let alone one dominated by variable renewables. Subsequent policies addressing emissions have been bolted on to a system whose basic architecture was never suited to the task.

Since around 2015, the response to these accumulating failures has been a sequence of patches rather than structural reform. New mechanisms have been added to deal with reliability shortfalls, system security, network congestion and investment risk. Emergency reserves, directions, administered prices, minimum generation constraints and even full market suspension have become normalised. Each intervention addresses an immediate problem, but none resolves the underlying contradictions of the system. The result is a market that no longer operates as designed, sustained instead by continual ad hoc intervention while still being described as market-based.

THE CLEAN ENERGY TRANSITION

The failure of the NEM design to respond to global heating reflects a missed opportunity to incorporate the prescriptions of market economics. It would have been possible for the market design to incorporate a pollution price, taking account of the adverse effects of particulate emissions and allowing the future incorporation of a carbon price.

Instead, we see the same pattern as in the NEM more generally: a patchwork of ad hoc adjustments that deliver less satisfactory outcomes at lower cost.

In the early stages of the transition, the Renewable Energy Target acted as a crude carbon price, though it did not reflect carbon intensity: retailers of electricity generated by gas, black coal and brown coal all faced the same requirement to buy renewable certificates. The Finkel Review[1] proposal to fix this with a Clean Energy Target went nowhere.

Now that the large-scale renewable target has been met, and with the Safeguard Mechanism inherited from the Abbott government doing little, if any, work, the set of policies driving decarbonisation include:

- The small-scale renewable energy target supporting rooftop solar;
- State renewable energy zones and reverse auctions;
- The Commonwealth Capacity Investment Scheme underwriting storage;
- The Integrated System Plan (ISP)[2] shaping transmission around assumed renewable build-out;
- Default retail obligations incorporating renewable procurement;

[1] Finkel et al. (2017) *Independent Review into the Future Security of the National Electricity Market*, https://www.dcceew.gov.au/energy/publications/independent-review-future-security-national-electricity-market-blueprint-future

[2] AEMO (2023), *Integrated System Plan (ISP) 2023*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp

- Publicly owned generators directed toward net-zero targets; and
- Corporate Power Purchase Agreements (PPAs) driven by ESG risk management.

These policies, along with the continuing decline in the cost of solar PV and storage, have produced significant progress towards decarbonisation. But this progress has been achieved in spite of the existing market not because of it.

INTERNATIONAL EXPERIENCE

Australia's experiment with market liberalism was not an isolated event, but part of a global shift. Integrated electricity supply systems were broken up, privatised and, at least notionally, regulation was replaced by markets. Although the details of design varied, the assumption that markets could be relied on both to promote efficiency and to optimise investment decisions were almost universal.

The first large-scale evidence that liberalised electricity markets were institutionally fragile emerged more than two decades ago. The California electricity crisis of 2000–01 demonstrated that market designs relying on scarcity pricing, fragmented ownership and incomplete coordination were vulnerable to both strategic behaviour and political constraints. Empirical analyses showed substantial inefficiencies and systematic market manipulation, particularly through withholding and exploitation of congestion.[3] The collapse of firms such as Enron was not an aberration but a predictable response to a partially deregulated system combining wholesale competition with capped retail prices and weak system oversight. California's subsequent shift toward long-term contracting by public authorities marked an early retreat from the investment-through-prices model.

Since then, similar patterns have appeared across liberalised systems. Comparative reviews of electricity reform conclude that competitive wholesale markets have consistently failed to deliver timely and efficient investment without extensive non-market support. In Great Britain, repeated market redesigns culminated in the introduction of contracts for difference, a capacity market and direct system operator procurement, leaving spot markets largely as short-run balancing mechanisms rather than investment drivers.

More recent work focuses on the interaction between liberalised markets and decarbonisation. As variable renewables scale up, wholesale prices become more volatile and average revenues decline, further weakening merchant investment incentives.[4] Governments have responded by expanding contracting, underwriting and regulated

[3] Borenstein, Bushnell and Wolak (2002) 'Measuring market inefficiencies in California's restructured wholesale electricity market', *American Economic Review*, pp 1376–1405, https://doi.org/10.1257/000282802762024557

[4] Joskow (2019) 'Challenges for wholesale electricity markets with intermittent renewable generation at scale: the U.S. experience', *Oxford Review of Economic Policy*, pp 291–331, https://doi.org/10.1093/oxrep/grz001

returns, even while maintaining the formal language of markets. In the European Union, this shift has been accompanied by a relaxation of state-aid constraints to accommodate long-term contracts and strategic reserves, reflecting recognition that market coordination alone is insufficient.

The Texas experience provides a particularly stark illustration. ERCOT retained an energy-only design longer than most jurisdictions, explicitly relying on extreme scarcity prices to finance reliability. During the February 2021 winter storm, prices rose to regulatory caps, yet the system still failed catastrophically. Losses were socialised after the event, and subsequent reforms moved toward greater reserve procurement and operational control. Wolak argues that such outcomes reflect a fundamental mismatch between energy-only market theory and the realities of political risk, correlated outages and system-wide shocks.[5]

Across this literature, a common conclusion emerges. Liberalised electricity markets have not failed because governments interfered too much, but because governments could not credibly commit to allowing outcomes that theory requires. Price caps, emergency interventions and ex post compensation are not policy errors but politically inevitable responses to system stress. The result is convergence toward hybrid systems in which markets survive as short-run coordination tools, while investment, reliability and decarbonisation are delivered through planning and contracts. The analysis in this paper aligns closely with that international experience.

[5] Wolak (2022) 'Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables', *Environmental and Energy Policy and the Economy*, https://doi.org/10.1086/717221

The case for structural separation

The Australian electricity system already operates as a hybrid of market and plan. Since at least 2015, reliability, security and investment outcomes have been delivered not by the energy-only pool alone, but by a growing layer of administrative interventions: reserve procurement, directions to generators, minimum synchronous generation constraints, system-strength rules, ad hoc plant life extensions, and even full market suspension. This creates an inherent institutional contradiction. AEMO is simultaneously required to run a neutral pool market and to override that market whenever it fails to deliver reliability. The result is blurred accountability and a system that is planned in practice but still presented as delivering market outcomes.

The case for splitting AEMO rests on recognising that two incompatible functions have been combined in a single institution. On the one hand, there is operation of a short-run pool market, intended to discover prices and dispatch generation based on bids and marginal costs. On the other, there is system stewardship: ensuring reliability, managing security services, planning networks, and intervening in emergencies. These functions obey different logics. Market operation is rule-bound and reactive; system management is discretionary, forward-looking and explicitly political. Asking one body to do both has produced exactly what we observe: repeated temporary fixes that become permanent, and a market that is routinely suspended or overridden in stress events.

The historical record since 2015 makes this clear. The cumulative layering of add-ons and overrides shows a consistent pattern: each intervention responds to a specific failure, but together they amount to a de facto planned system without explicit design or accountability.

- **2015–16:** Event: increased use of constraints and directions to keep synchronous plants online. Trigger: ageing coal reliability produces rising coal outage rates and volatility increases.
- **September 2016:** Recognition that inertia and system strength are essential but unpriced; beginnings of formal frameworks, increased politicisation of key aspects of the system. Trigger: South Australian blackout. Storm damage combined with loss of system strength and inadequate fault ride-through.
- **2017:** Energy Security Board established. Trigger: Finkel Review concludes existing market governance is not fit for a transitioning system, but the proposed response (Clean Energy Target) is politically unacceptable.
- **2017–18:** Expansion of Reliability and Emergency Reserve Trader, reserve procurement outside the market becomes a standing backstop. Trigger: forecast reliability shortfalls linked to coal closures and peak demand.

- **2018–19:** Mandatory system-strength obligations and constraints forcing synchronous generation to run regardless of price. Trigger: rising non-synchronous generation reduces fault levels.
- **2019:** Retailer Reliability Obligation (never triggered because emergency tools intervene first). Trigger: concern that energy-only prices would not deliver sufficient capacity.
- **2020–21:** Minimum synchronous generation requirements, suppressing price-based dispatch. Trigger: minimum-demand periods with high rooftop and utility PV.
- **2021–22:** Increased directions, expanded RERT, pressure to delay coal retirements. Trigger: long unplanned outages coinciding with fuel constraints.
- **June 2022:** Full market suspension. Trigger: price caps, outages and bidding behaviour cause market breakdown.
- **2022–23:** Administered pricing and compensation. Trigger: continuing volatility and risk of repeat failure.
- **2023–24:** ISP transmission planning intensified. Trigger: congestion, curtailment and failure of private networks to anticipate renewables.
- **2024–25:** Reliability and Emergency Reserve Trader (RERT) and contracted load shedding treated as routine tools. Trigger: ongoing reliability risks during peaks and outages.
- **Emerging:** Distributed Energy Resource (DER) and Virtual Power Plant (VPP) emergency control powers. Trigger: high rooftop PV penetration creates new minimum-demand risks.

This proliferation of interventions undermines the idea that the pool market operates to balance underlying supply and demand for a homogeneous commodity (electricity), either in the short run or the long run. The logical response is to return AEMO to its original role, and to roll the other interventions into a coherent whole. The required reform is to split AEMO into two entities.

The first would be a pure pool market operator. Its role would be limited to running the spot market, dispatching bids according to published rules and settling prices and quantities transparently. It would not procure reserves, issue directions, plan networks, underwrite investment, or manage emergencies.

The second would be a national grid and system manager with an explicit public mandate. As with AEMO, the national grid manager would be jointly owned and run by the Commonwealth and states. This body would handle all ancillary and reliability functions now bolted onto the market, plan and operate the transmission system, nationalise transmission networks, and manage future extensions as anticipatory public infrastructure rather than reactive private investments. It would contract generation capacity through long-term

power purchase agreements with both public and private generators, allocating risk explicitly rather than hiding it in price volatility.

Responsibility for default retail offers would also sit with the system manager, along with a formal mandate to assess the performance of retail competition. Empirically, retail electricity competition in Australia has delivered limited benefits to most households. Switching rates are low and highly concentrated among a small, engaged minority; price dispersion largely reflects tariff complexity rather than cost differences; and advertised discounts have functioned mainly as marketing devices rather than indicators of underlying efficiency. The continued reliance on regulated default offers is itself evidence that retail competition has not delivered transparent or reliable outcomes for a large share of consumers.

Emissions should be incorporated into the system. Given the toxic politics of carbon pricing, this should be done implicitly rather than through an explicit carbon price. The system manager should include emissions intensity as a scored criterion in PPA procurement, alongside cost, reliability and locational value. Retailers sourcing energy from the pool should face expanded clean energy obligations that rise with portfolio emissions intensity. Emergency reserves and reliability procurement should also take emissions into account, preventing back-door carbon lock-in. Default retail offers should reflect the emissions profile of the contracted system portfolio.

International experience suggests that this form of institutional separation is not anomalous. In Great Britain, the system operator function has been progressively separated from market operation, with explicit responsibility for system planning, balancing and ancillary services, while energy trading is supported by long-term contracts and capacity mechanisms. In much of the EU, transmission system operators play an explicit planning and procurement role alongside energy markets supplemented by contracts for difference, capacity arrangements and reliability options.

The alternative to institutional separation is continued improvisation: a market that claims neutrality while relying increasingly on planning and emergency intervention. Splitting AEMO would make those interventions explicit, disciplined and accountable, without increasing their scope.

Transmission

Transmission deserves separate treatment because it is the point at which the gap between market rhetoric and system reality is widest. Whatever view one takes of generation markets, transmission is a natural monopoly with long asset lives, large sunk costs and strong network externalities. This has led most state governments, with the exception of Victoria, to retain ownership of transmission networks.

The proposed national grid manager would integrate the state and territory networks (except Western Australia and the Northern Territory) and would also acquire the privately owned Victorian networks. It may therefore be worth restating the case for public ownership and for the integration of transmission network ownership and grid management more generally. The economic case for private ownership was always weak, and looks weaker still in a high-renewables system that requires anticipatory, coordinated expansion rather than incremental, reactive upgrades.

Governments borrow more cheaply than any private owner of transmission assets, and the difference matters because transmission is overwhelmingly capital cost with very low operating risk once built. Past privatisations transferred assets that could be financed at sovereign rates into structures requiring materially higher returns, with no corresponding gain in efficiency or innovation. The result was higher required revenues, more complex regulatory regimes to protect consumers, and a permanent wedge between the social cost of capital and the private cost imposed on users. In the case of transmission, where utilisation is system-determined and innovation is limited, the standard arguments for private risk-bearing do not apply.

Transmission planning is also unavoidably political. Decisions about where lines run, which regions are connected first, and how costs are shared are not neutral technical optimisations. Under private ownership these political choices are displaced into regulatory processes and planning disputes, where they reappear as delay, litigation and community conflict. Integrating transmission planning with a publicly accountable grid manager allows political and economic trade-offs to be addressed together rather than colliding late in the process.

Taken together, these considerations reinforce the case for nationalising transmission and placing it under a single grid and system manager. Lower financing costs reduce the real resource cost of the transition. Integrated planning aligns economic efficiency with political feasibility. Public ownership reduces exposure to strategic and geopolitical risk.

Generation

On generation, the framework proposed here supports a mixed public–private model and preserves meaningful choice. Generators may choose between merchant operation in the pool market or long-term PPAs with the grid manager. Most new renewables already rely on contracts, while some storage, peaking and legacy plant remains merchant. Formalising this dual pathway removes the fiction that a single market structure must serve all technologies equally well.

Public ownership of some generation assets fits naturally within this model and continues existing state practice. A mixed ownership structure also mitigates the weaknesses of the earlier private oligopoly, where credible claims of market manipulation and strategic bidding were recurrent during periods of stress.

In generation, the proposed framework supports a mixed public–private model and is best understood as a continuation rather than a reversal of current policy directions. Most states have already moved back toward some public ownership or public underwriting of generation, particularly for renewables and firming capacity. This reflects practical considerations rather than ideology. Generation investment now depends heavily on long-term contracts, risk allocation and system integration, all of which sit more naturally with public participation. At the same time, there is no case for excluding private capital. Private generators can and should continue to operate alongside public entities, bidding for PPAs on equal terms and competing on cost, reliability and system value.

This approach also addresses a persistent weakness of the earlier fully privatised model. When generation was dominated by a small number of privately owned thermal generators, credible allegations of market manipulation were recurrent. Tight oligopoly conditions, capacity withholding, and strategic bidding were widely discussed, particularly during periods of stress. Whether or not these behaviours always breached formal rules, they reflected the underlying incentive structure of an energy-only market with concentrated ownership. A mixed ownership model, combined with contract-based revenue and order-of-merit operation, reduces the scope and payoff for such behaviour. Diversity of ownership is not a substitute for regulation, but it materially lowers the risk that market power translates into systemic outcomes.

GENERATOR ENTRY AND EXIT

Generator entry and exit must be treated as system design questions rather than left to price signals alone. In the original design of the NEM, merchant entry was meant to provide insurance capacity, rewarded by high prices during scarcity events. In practice, caps on

maximum pool prices, administered pricing and emergency interventions truncate scarcity rents precisely when they would need to be realised. Merchant entry therefore cannot reliably finance insurance capacity, and expectations that it will do so are inconsistent with the actual rules of the system. Emergency procurement then fills the gap, further undermining merchant incentives. For this reason, merchant entry should be treated as optional and opportunistic rather than a cornerstone of system adequacy.

Contracted entry would occur through grid-manager tenders based on assessed system needs. Merchant entry would remain possible, but would not be relied upon for reliability. Exit of contracted generators would be governed by explicit contractual terms, while merchant exit would remain a commercial decision. Legacy plant retirement would be planned rather than crisis-driven.

Exit would likewise be differentiated. For merchant generators, exit would be a commercial decision governed by market conditions and asset economics. For contracted generators, exit would be managed through contractual terms. PPAs would include provisions governing early closure, life extension, and transfer of ownership, with penalties or compensation reflecting system impact. This makes the cost of exit explicit rather than socialised through emergency interventions or political pressure, as has occurred with coal plant retirements.

A critical function of the grid and system manager would be managing the transition of legacy assets, particularly ageing coal and gas plants. Rather than relying on opaque negotiations or last-minute interventions, the system manager would set clear expectations about retirement windows, availability obligations and contingency arrangements. Where temporary extensions are justified on reliability grounds, they would be contracted explicitly and priced accordingly. Where exit is inevitable, replacement capacity would be procured in advance. This replaces crisis management with planned transition.

The framework also allows movement between merchant and contracted status over time. A merchant generator facing declining revenues may seek a contract if it provides system value, such as flexibility or firming. Conversely, a contracted generator may return to merchant operation at contract expiry. Entry and exit are therefore not binary events, but part of a managed lifecycle. What matters is that system adequacy does not depend on uncontracted plants staying online longer than is economically or politically sustainable.

By separating entry and exit decisions from spot market volatility, the system reduces the risk of investment droughts followed by overbuilding, a pattern that has characterised electricity markets internationally. More importantly, it reduces the likelihood that governments will be forced into ad hoc interventions to prevent politically unacceptable outages. Entry and exit still occur, but on terms that are transparent, predictable and consistent with system objectives rather than driven by crisis.

ROOFTOP SOLAR, STORAGE AND VIRTUAL POWER PLANTS

The designers of the NEM did not anticipate the possibility that consumers would generate their own power, let alone return it to the grid. The result has been long-running conflict between public policies aiming to promote rooftop solar (feed-in tariffs, the Small Scale Renewable Energy Scheme, battery subsidies) and efforts by NEM participants to push back and penalise home generation.

A path to possible resolution is provided by virtual power plants, enabled by more sophisticated metering technology. Virtual power plants link multiple home systems, enabling them to transmit power into the grid when it is valuable, and consume it when prices are low.

A public system manager would allow a more co-ordinated push towards virtual power plants. Ideally the small-scale efforts currently being developed would be acquired and merged to form the basis of a comprehensive policy framework in which virtual power plants became the default rather than an obscure and complex option.

Distribution and retail

The changes proposed above have some implications for distribution and retail.

DISTRIBUTION

Distribution raises a related but distinct set of issues. From a strictly economic perspective, many of the arguments for public ownership of transmission apply equally to distribution networks. Distribution is a natural monopoly, characterised by long-lived assets, high sunk costs, and extensive regulation to control prices and service quality. Competition plays no meaningful role in disciplining behaviour once assets are built, and efficiency gains from private ownership have been modest at best. In that sense, full public ownership of distribution would be logically consistent with the broader framework proposed here.

However, logical consistency is not the same as policy priority. Distribution networks, while facing growing challenges from electrification, rooftop PV, electric vehicles and changing load profiles, are not currently the binding constraint on system reliability or decarbonisation. Transmission, system coordination and generation investment pose more immediate risks. Attempting wholesale renationalisation of distribution at the same time as restructuring system management and transmission would add political and administrative complexity without delivering commensurate near-term benefits.

A more proportionate response is therefore preferable. The core economic issue in distribution is not ownership per se, but the level of allowed returns on capital. Distribution businesses remain regulated monopolies whose revenues are determined by the regulatory asset base and the allowed rate of return. Those returns were set under assumptions about risk and financing costs that no longer hold. Lowering allowed rates of return to reflect contemporary conditions would capture much of the efficiency gain associated with public ownership, without the disruption of immediate acquisition.

At the same time, governments could make standing offers to repurchase distribution assets at regulated asset base value. This would provide an orderly, non-coercive pathway back to public ownership over time, should private owners prefer to exit under tighter regulatory settings. Such an approach avoids forced acquisition, reduces litigation risk, and ensures that any transition occurs on transparent and economically defensible terms.

This staged approach has two advantages. It restores coherence by recognising that distribution is not meaningfully competitive, while avoiding the risks of attempting too much reform at once. And it disciplines incumbent owners by aligning returns with genuine risk, rather than allowing monopoly rents to persist behind complex regulatory processes. Public ownership remains available as a fallback rather than a precondition for reform.

In combination with the proposed changes to system management, transmission and generation, this approach to distribution completes a coherent institutional design. Markets are used where they add value, regulation is tightened where monopoly persists, and public ownership is deployed selectively where it lowers costs, improves accountability, and reduces systemic risk.

RETAIL

Responsibility for default retail offers should also sit with the grid and system manager, along with a formal mandate to assess whether retail competition is delivering net benefits to consumers. Retail electricity markets were justified on the promise of innovation, price discovery and consumer choice. The empirical record is weak. Most households do not actively switch, price dispersion largely reflects complexity rather than cost differences, and "discounting" has functioned primarily as a marketing device rather than a productivity gain. The need for regulated default offers is itself evidence that retail competition has not delivered transparent or efficient outcomes for a large share of consumers.

Placing default retail offers within the system manager's remit would make the logic explicit. Retail competition would be allowed to operate where it demonstrably adds value, but the benchmark price faced by passive consumers would be treated as a public service obligation rather than a residual market artefact. This would also align retail pricing more closely with system costs and reliability decisions, rather than leaving households exposed to volatility generated upstream by market and operational failures.

Objections and responses

A common objection to splitting AEMO is that it would fragment responsibility and weaken coordination in an already complex system. This concern rests on a misunderstanding of the current situation. Responsibility is already fragmented, but informally and opaquely. Market operation, reliability assurance, system security, investment planning and emergency intervention are handled within a single institution through different committees and discretionary powers, often pulling in different directions. Formal separation would not create fragmentation so much as make existing functional divisions explicit, with clearer mandates and lines of accountability. Coordination problems are more likely when responsibilities are blurred than when they are clearly assigned.

A related objection is that separation would undermine the neutrality of the market operator. In practice, neutrality has already been compromised by the accumulation of directions, constraints and out-of-market interventions required to keep the system operating. The market operator is routinely placed in the position of suspending or overriding its own market outcomes. Splitting functions would strengthen, not weaken, neutrality by confining the pool market to rule-based dispatch and settlement, while locating discretionary intervention in a body explicitly charged with system management and accountable for those decisions.

It is also argued that splitting AEMO would add institutional complexity and transition costs. This is true in a narrow sense but misleading in a broader one. Complexity has already increased dramatically, as evidenced by the proliferation of special regimes, emergency powers and bespoke mechanisms layered onto the original market design. The question is not whether complexity exists, but whether it is organised coherently. A single, explicit grid and system manager would simplify the overall architecture by consolidating functions that are currently scattered across multiple frameworks and justified as exceptions.

Another objection is that separation risks entrenching central planning and crowding out market signals. This reverses causality. Central planning has already emerged because market signals alone no longer deliver reliability, security or timely investment. The proposed split does not eliminate markets; it confines them to what they do well, namely short-run coordination and dispatch. Planning is unavoidable for networks, reliability and long-lived capital assets. The real choice is between explicit, accountable planning and implicit planning through crisis management and regulatory improvisation.

Some critics argue that a split would reduce flexibility and slow response in emergencies. The opposite is more plausible. Under the current arrangement, emergency powers sit awkwardly alongside market functions, creating legal and procedural uncertainty about when and how they should be used. A dedicated system manager with clear authority over

reserves, demand response and rationing would be better placed to act decisively, precisely because emergency action would be its core mandate rather than an exception to normal operations.

Finally, it is sometimes suggested that international practice favours integrated system and market operators, and that Australia would be out of step. This claim does not survive inspection. High-renewables systems increasingly separate market operation from system planning and procurement, even where formal institutional boundaries differ. What matters is not the organisational chart but whether system management functions are treated as primary responsibilities rather than ad hoc overlays. On that criterion, the Australian model is already converging toward separation in practice, without having acknowledged it institutionally.

Taken together, these objections point less to flaws in the proposal than to discomfort with making explicit changes that have already occurred implicitly. Splitting AEMO would not introduce new principles into the system. It would recognise existing realities, clarify responsibilities, and reduce the reliance on discretionary fixes that currently substitute for coherent design.

A final, predictable, objection is that this amounts to renationalisation by stealth. There is nothing stealthy about the proposal. It reflects an explicit assessment that privatisation has failed on its own terms in transmission and system coordination, and that financial constraints assumed at the time no longer apply. Public borrowing costs are lower, risks are already socialised through intervention, and redesign is a response to evidence rather than ideology.

Concluding comments

After decades of ad hoc patches, the elegant design of the original NEM is almost invisible. In part, that reflects poorly thought-out political reactions to short-term emergencies. But the fundamental problems were inherent in the original design. The implicit assumption of the design was that private capital markets, responding to prices in pool markets, would yield optimal investment decisions. Enthusiasm for competition encouraged designers to wish away problems of market concentration and inadequate consumer information.

It is now time for a fundamental restructuring. The market should be left to do what markets do best: match supply and demand in the short run. The larger task of planning and operating a national grid, and the process of transition to clean energy, should be undertaken by a single national authority, overseen by state and federal governments.

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