

Centralised regulation, decentralised control: The political economy of electricity distribution regulation in Australia

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Abstract

Australia's mid-2000s electricity reforms transferred economic regulation of distribution networks from state regulators to the Australian Energy Regulator (AER) while assigning detailed rule-making to a separate Australian Energy Market Commission (AEMC). This paper re-examines those arrangements as a political-economy settlement rather than simply a technocratic regulatory reform. The Commonwealth sought a genuinely national regulatory system and a single electricity and gas regulator located in the Australian Competition and Consumer Commission (ACCC). The states resisted the loss of jurisdiction and, in several cases, retained ownership of the businesses that would be regulated. The eventual settlement centralised formal revenue regulation but left substantial authority elsewhere: states retained important ownership and planning functions, while detailed economic rules were assigned to a separate institution established outside Commonwealth administration. Subsequent experience exposes the significance of that incomplete centralisation. State-imposed reliability and planning standards contributed to a large expansion of network investment. A synthetic NEM transfer benchmark indicates that real distribution RAB per customer is now about 27 per cent higher than at transfer. The AER's current benchmarking series shows aggregate total factor productivity declining over 2006–24 and a persistent decline in capital productivity. The paper also shows that electricity production has become far more decentralised since the settlement was designed, while the claimed administrative scale economies from centralisation are not readily visible in regulatory staffing. International comparison, technology changes and the increasingly local character of distribution reinforce the case for reconsideration. Formal responsibility for distribution economic regulation should return to participating jurisdictions, while common data, regulatory accounting and benchmarking should be retained.

Keywords: electricity distribution; economic regulation; federalism; government ownership; political economy; Australian Energy Regulator; Australian Energy Market Commission; decentralisation.

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1. Introduction

Australia created a national electricity market without initially creating a national regulator of local electricity distribution. When the National Electricity Market (NEM) commenced, wholesale-market institutions operated across participating jurisdictions, the Australian Competition and Consumers Commission (ACCC) regulated transmission access, and state regulators determined the revenues of electricity distributors. Within a few years the Commonwealth was pressing for a different arrangement: one national electricity and gas regulator located in the ACCC, ultimately including distribution. The states and territories resisted. The compromise eventually reached created the Australian Energy Regulator (AER) and the Australian Energy Markets Commission (AEMC) and progressively transferred distribution economic regulation from the states to the AER. The questions examined here are why this happened, what interests shaped the settlement, and whether a compromise reached more than twenty years ago should continue to determine the regulatory geography of electricity distribution today (Parer et al., 2002; MCE, 2003; National Archives of Australia, 2024).

These are contemporary questions. The AEMC is undertaking a comprehensive Electricity Network Regulation Review covering the boundaries of monopoly services, revenue determination, expenditure incentives, risk allocation and the role of networks during the energy transition. Network regulation is consequently under close examination. However in this review the institutional geography is largely taken as given: the AEMC makes the detailed rules and the AER applies them to distribution networks across the NEM. A review of the regulatory framework should also ask whether the institutions and geographical allocation through which that framework is made and applied remain appropriate (AEMC, 2026a, 2026b).

The conventional history presents centralisation as part of the creation of a more consistent and efficient national energy market. The earlier arrangements involved multiple regulators and overlapping national institutions. Businesses operating across jurisdictions faced inconsistent licences and regulatory requirements, while government ownership created potential conflicts between the roles of owner, policymaker and regulator. The ACCC argued that a single, consistent regulator could reduce compliance costs, regulatory uncertainty and barriers to interstate business. Parer likewise concluded that harmonisation between regulators would not deliver a genuinely national approach and recommended one National Energy Regulator (Parer et al., 2002; ACCC, 2004).

The history is nevertheless more complicated than a simple progression from fragmented to national regulation. The Commonwealth could not assume responsibility for state electricity distribution unilaterally. Energy remained substantially a state responsibility and reform required intergovernmental agreement, giving the states bargaining power over the form and limits of the new institutions. Their interests were not identical. Victoria and South Australia had privatised or leased their distribution businesses, whereas New South Wales, Queensland and Tasmania retained substantial government ownership. For an owning government, regulation was not merely an issue of administrative geography because regulatory decisions affected the revenues, investment, value and financing of businesses from which the government received financial returns (Mountain and Littlechild, 2010; Mountain, 2014, 2019).

The resulting institutional settlement is revealing. Formal distribution revenue regulation moved to the national level, but control over all the determinants of network expenditure did not. States retained ownership and set reliability and planning standards. Detailed economic rules were made by the separate AEMC, established under South Australian legislation and funded by participating jurisdictions. The AER was located within the ACCC, as the Commonwealth had wanted, but the appointment of its members also gave the jurisdictions substantial influence. Australia therefore centralised regulation without centralising control, a distinction that helps explain both the origins of the arrangement and some of its subsequent consequences.

Those consequences became particularly visible during the large increase in electricity-network investment from the mid-2000s. Simshauser and Akimov (2019) identify mistaken demand expectations and tighter reliability standards, particularly following supply interruptions in Sydney and Brisbane, as central drivers of the expansion. The regulated asset base of NEM electricity networks rose from about \$32 billion in 2004 to \$93 billion in 2018. The Productivity Commission similarly concluded that spiralling network costs reflected defects in reliability and

regulatory arrangements and described some reliability requirements as prescriptive and politically influenced (Productivity Commission, 2013; Simshauser and Akimov, 2019).

The planning-standard explanation and the ownership literature answer different questions. Reliability standards provide an important proximate explanation for investment, while ownership helps explain why the regulated asset and revenue outcomes of government-owned Australian distributors differed so markedly from those of investor-owned counterparts. Mountain (2014, 2019) finds evidence that ownership materially affected regulatory outcomes and argues that regulating government-owned monopolies as if they were privately financed created distinctive investment incentives and weakened the practical meaning of independent regulation. The central argument developed below is that these findings belong together: state governments retained important levers capable of driving network expenditure after formal economic regulation was centralised, while in several jurisdictions those same governments owned the businesses benefiting from regulated investment.

This paper contributes at the intersection of three literatures. Australian studies have examined AER institutions, ownership, network costs and investment outcomes (Mountain and Littlechild, 2010; Nepal, Menezes and Jamasb, 2014; Mountain, 2014, 2019; Simshauser and Akimov, 2019). The federalism literature asks how regulatory jurisdiction should be allocated when spillovers and information differ across levels of government (Oates, 1999; Trillas, 2010), while the distributed-energy literature examines how technological change alters the tasks and methods of distribution regulation (Jenkins and Pérez-Arriaga, 2017; Bell and Gill, 2018; Burger et al., 2019; Bovera et al., 2021). Less attention has been given to regulatory geography itself. The contribution here is to treat Australia's centralisation as a political-economy settlement, relate it to retained state powers and ownership, assess its subsequent performance, and ask whether common data, benchmarking and NEM-wide rules require a single national decision-maker. This also extends the discovery-process argument from regulatory methods to institutional arrangements (Littlechild, 2014).

The argument has wider relevance because electricity systems are becoming simultaneously more integrated and more decentralised. Wholesale markets and transmission increasingly require coordination across large geographical areas, while distribution increasingly depends on local information about rooftop generation, storage, flexible demand, electric vehicles, new loads and state or regional planning. Australia is a useful case because it began with a functional federal division then consciously centralised distribution regulation and now has two decades of experience with the result. The paper reconstructs that political and institutional bargain, examines subsequent evidence, and asks whether common information and benchmarking can be preserved without requiring a single national decision-maker.

2. From a national electricity market to a national regulator

2.1 The original NEM was functionally federal

The original NEM did not equate national market institutions with Commonwealth control of all regulatory functions. The National Electricity Market Management Company (NEMMCO) operated the wholesale market and power system. The National Electricity Code Administrator (NECA) administered the National Electricity Code and its change process. The ACCC regulated transmission access, and jurisdictional regulators regulated electricity distribution. Activities with substantial interstate effects were therefore handled at the wider level, while geographically local monopoly networks continued to be regulated in their jurisdictions.

That division was not necessarily regarded as permanent. The 1990s reform programme had emerged from National Competition Policy and a wider effort to remove state barriers to trade, expose contestable activities to competition and develop national approaches to infrastructure access. By the early 2000s, the Commonwealth and market institutions increasingly regarded differences among state regulatory systems as obstacles to completion of a genuinely national energy market. The ACCC described the AER as a continuation of National Competition Policy reforms and argued that national consistency across gas, electricity and jurisdictions would reduce regulatory costs and barriers to investment (ACCC, 2004).

2.2 Why the Commonwealth wanted a national regulator

The Commonwealth case combined market integration, institutional consistency and regulatory independence. A retailer or energy business operating in several states could face different licensing, marketing, reporting and consumer-protection obligations. Gas and electricity networks could be treated differently despite competing to serve similar energy requirements. Regulators also required specialist economic, legal, engineering and financial capability. A larger institution promised deeper expertise and a larger pool of comparative information, while a national body appeared less exposed to the conflicts created where a state government simultaneously owned electricity businesses and shaped the regulatory framework.

The 2002 Independent Review of Energy Market Directions chaired by Warwick Parer gave these arguments their most comprehensive expression. It identified confused governance, too many regulators, overlapping responsibilities, weak Code-change processes and perceived conflicts of interest where governments were owners, policymakers and regulators. The Review rejected continued reliance on cooperation between separate regulators, arguing that different interpretations and implementation would remain, and recommended a statutory National Energy Regulator combining energy-related ACCC functions, jurisdictional economic regulation and relevant NECA functions (Parer et al., 2002).

Parer nevertheless bundled together problems with different economic characteristics. The clearest evidence of compliance costs concerned retailers and other businesses operating across state borders. A distribution network does not choose in which state to provide its monopoly service because its customers and assets are geographically fixed. Parer's distribution-specific criticisms, including investment incentives, asset valuation, service quality and embedded-generation connections, were principally questions about regulatory design. Common definitions, reporting requirements and connection rules can be national without requiring one institution to make every revenue determination.

The quantitative case was similarly indirect. The ACIL Tasman modelling commissioned for the Review assumed that the overall governance and regulatory reform package would reduce electricity and gas prices by around one per cent, principally through reduced regulatory risk, and calculated economic gains conditional on that assumption. It did not estimate the specific effect of transferring distribution regulation from jurisdictional regulators to one national regulator or compare that option with harmonised but decentralised regulation (Parer et al., 2002). The Commonwealth and Parer case for stronger national institutions was plausible, but the evidence for centralising the economic regulation of geographically fixed distribution monopolies was considerably thinner.

3. What did the states stand to lose?

3.1 Regulation was a state function, not an administrative convenience

The Commonwealth objective encountered a basic institutional fact: energy policy and electricity distribution were principally state responsibilities. The NEM had itself been created through cooperation among jurisdictions, and the national energy laws depended on participating jurisdictions agreeing to confer functions and adopt common legislation. Transfer of distribution regulation therefore required governments to surrender responsibilities they already possessed rather than merely rearranging Commonwealth administrative machinery (Australian Energy Market Agreement, 2004).

Regulatory jurisdiction also has practical value. It allows a government to accommodate local policy objectives, reliability preferences, ownership structures and political priorities. Even where a regulator is formally independent, the legal framework, statutory objectives, appointments and surrounding policy remain products of government. The National Archives account of the 2003 Cabinet papers confirms that the transfer was an active intergovernmental contest: the Howard Government sought a national legislative framework, a single electricity and gas regulator located in the ACCC, a national distribution and retail code and national transmission planning arrangements, while states and territories resisted the Commonwealth objective of a single ACCC regulator (National Archives of Australia, 2024).

3.2 Ownership made the issue more than constitutional

The stakes were sharper in jurisdictions that owned electricity distributors. A government owning a regulated enterprise occupies several positions at once. As policymaker it is concerned with prices, reliability and voter reactions; as owner it receives dividends and other returns and bears consequences for the value and borrowing requirements of the business; and through legislation and appointments it influences the regulatory framework within which the enterprise operates. Mountain and Littlechild (2010) pointed to the significance of this combination when comparing New South Wales with Great Britain and Victoria, noting that an owning government has an additional interest in the profitability and regulatory treatment of the business.

The Cabinet record establishes state resistance to the Commonwealth model but does not establish that protecting distribution profits was the motive for that resistance, and privatised jurisdictions also had reasons to protect constitutional responsibility and policy autonomy. Ownership nevertheless changed the stakes for some participants. Subsequent evidence reinforces the economic relevance of that distinction: Mountain (2014) argues that apparently independent price-cap regulation produced markedly different results when applied to Australian government-owned distributors, while Mountain (2019) finds government ownership associated with materially higher regulated asset values and revenues after controlling for observable network characteristics.

3.3 Independence has different meanings under government ownership

The standard case for independent utility regulation is largely a commitment argument. A private investor asked to sink capital into long-lived assets may fear that government will subsequently reduce prices once investment is irreversible, so an arm's-length regulator can make opportunistic intervention more difficult and lower regulatory risk. The problem looks different where the government itself owns the regulated enterprise. Government cannot expropriate itself in the ordinary sense; instead, ownership can create an interest in regulatory arrangements that sustain asset values, profits and cash flows while visible price decisions are made by an institution presented as independent (Mountain, 2014).

Moving the final revenue determination away from state government can remove one obvious conflict, but it does not remove the government's ownership interest or its capacity to shape expenditure through reliability requirements, planning standards, licence conditions, taxation, borrowing arrangements or energy policy. Independence of the revenue determination is therefore only one component of independence of the regulatory outcome. The experience after 2005 provides evidence of the importance of these retained state powers.

4. The federal bargain: centralisation with divided control

4.1 From Parer's one regulator to two bodies

Governments did not implement Parer's recommended institutional structure. The Ministerial Council on Energy assigned rule-making and market-development functions to the AEMC and regulation and enforcement to the AER, with distribution regulation transferring progressively from jurisdictional regulators to the AER (MCE, 2003). There was a legitimate functional rationale for distinguishing rule-making from implementation. A regulator that writes the rules it subsequently applies may design them around its own administrative convenience, while a separate rule-maker can take a wider view and expose proposed changes to an independent consultative process. The near-contemporaneous IEA review described separation of rule-making from implementation as a motivation for creating two institutions (IEA, 2005).

Functional separation does not, however, require separate statutory organisations. Rule-making, adjudication and enforcement can be separated internally within one regulator, as they are in all known comparator systems. The reviewed 2003 material contains no comparative institutional assessment showing why two separate bodies were preferable to a single regulator with internal separation, or weighing the benefits of specialisation against information, coordination and accountability costs. The particular two-body form is easier to understand when the federal negotiations are brought back into the story.

4.2 The settlement divided institutional influence

The AER was located and funded within the ACCC, giving the Commonwealth an important part of what it had sought, but it was not placed under exclusive Commonwealth control. Under the original Australian Energy Market Agreement, two of the three AER members were to be recommended by participating state and territory ministers, and appointment of the chair involved both the Commonwealth and jurisdictions. The AEMC was established as a separate statutory body under South Australian legislation. Two of its three commissioners, including the chair, were appointed following nomination by participating states and territories, with the remaining commissioner nominated by the Commonwealth (Australian Energy Market Agreement, 2004; AEMC, 2009).

The legal architecture also retained a cooperative federal character. The AEMC was national rather than Commonwealth in administrative form, was funded by participating jurisdictions and operated within an intergovernmental governance framework. The AER sat within Commonwealth administration, but its distribution functions arose through the cooperative national energy laws. The settlement can therefore be read as an allocation of gains and losses from centralisation: the Commonwealth purportedly obtained nationalisation of formal economic regulation and a regulator located in its preferred ACCC framework, while the states surrendered individual determinations but retained substantial collective influence over the new institutions and important ownership, planning and policy powers.

5. What happened after centralisation?

5.1 Centralising revenue regulation did not centralise the drivers of expenditure

Economic regulation is often described as a regulator determining efficient expenditure and allowed revenue, but many important decisions precede this. Reliability standards determine what capability must be provided, planning and connection requirements shape investment obligations, governments can mandate programmes or development objectives, and ownership affects financing incentives and corporate objectives. Australia centralised only parts of this chain. New South Wales and Queensland tightened distribution reliability or planning requirements during the mid-2000s, and jurisdictional regulators reopened or altered recently completed determinations to accommodate higher expenditure. Once the AER assumed responsibility, it regulated businesses subject to state instruments and policy requirements that it did not control (Productivity Commission, 2013; Mountain, 2017).

Simshauser's work gives the episode broader quantitative significance. Simshauser and Akimov (2019) report that the regulated asset base of NEM electricity networks rose from approximately \$32 billion in 2004 to \$93 billion in 2018, with forecast demand growth and tighter reliability standards among the important drivers. Demand subsequently contracted, leaving a substantial volume of investment that proved unnecessary in retrospect. The Productivity Commission reached a related conclusion in 2013, finding that network costs were the principal contributor to a 70 per cent real increase in average electricity prices between June 2007 and December 2012 and criticising prescriptive and sometimes politically influenced reliability standards. It estimated that a reliability framework more closely reflecting consumers' preferences could defer around \$1.1 billion of distribution investment in New South Wales alone (Productivity Commission, 2013; Simshauser and Akimov, 2019).

5.2 Planning standards and ownership are complementary explanations

Reliability standards and ownership address different parts of the investment story. Simshauser and Akimov (2019) help explain the time-series event, namely why network capital expenditure rose so strongly during a particular period. Mountain (2014, 2019) asks a cross-sectional political-economy question: why the accumulation of regulated assets, revenues and profits was so much larger among government-owned Australian distributors than among privately owned peers operating under broadly comparable economic regulation. The two explanations can operate together rather than compete.

Planning standards can create politically required investment opportunities, while ownership affects the incentives of the distributor and government in setting, accepting and responding to those requirements. A government-owned distributor may also face a lower actual financing cost while regulation remunerates it using a private-

sector benchmark. If investment expands the regulated asset base on which the business earns an allowed return above its own financing hurdle, the enterprise and owner can face a stronger incentive to expand assets. The historical observation is therefore not simply that state governments imposed standards, but that responsibility for those standards remained with the states after economic regulation was transferred (Mountain and Littlechild, 2010; Mountain, 2014, 2019). The incentives to expand regulated assets (and the planning standards that would help to deliver that outcome) were stronger for the government-owned distributors since the regulatory arrangements specified by the AEMC ignored the government distributors' access to cheaper government borrowing and the owning governments' collection of income taxes on their profits.

5.3 The national regulator did not eliminate the owner-government problem

Separating state government from the regulator making the final revenue decision removed one obvious conflict, because a state minister could no longer exercise direct control over a state distribution determination through ordinary state machinery. The deeper conflict nevertheless remained. A state could continue to own the network, set reliability and planning obligations, receive financial returns from the regulated business, participate in national energy governance, and attribute the final revenue determination to the independent AER. Regulatory independence at one point in the chain therefore coexisted with governmental influence elsewhere.

Mountain (2014, 2019) describes the underlying issue as a problem with ownership-invariant regulation. Regulation designed principally for investor-owned monopolies assumes a shareholder seeking commercial returns and a government with no direct financial interest in those returns. Applying the same framework to a government-owned enterprise changes both sets of incentives, so ownership cannot simply be assumed away. Centralisation altered the identity of the price regulator, but it left in place important governmental incentives shaping important inputs to the determination, particularly in respect of government-owned distributors.

5.4 Capital intensity continued to increase and productivity continued to decline after centralisation

Because the AER assumed responsibility for distribution regulation at different dates in different jurisdictions, a common calendar-year comparison of AER and jurisdictional regulation gives a misleading starting point. A synthetic transfer benchmark is therefore constructed by taking each jurisdiction in the final year before its first AER revenue determination, aggregating the corresponding regulated asset bases and customer numbers, and then calculating the ratio. Expressed in June 2025 dollars, the matched observations give a distribution RAB of approximately \$64.0 billion serving 9.2 million customers, or about \$7,000 per customer. The customer-weighted date of this benchmark is approximately late 2009. The virtue of the measure is that numerator and denominator are matched and each jurisdiction is observed immediately before national regulation became operative for it (author's calculations).

Table 1. NEM distribution regulated asset base and customers at transfer to the AER and in 2025

Measure	At transfer to AER*	2025 NEM-only†	Real change
Distribution RAB, June 2025 \$bn	64.0	97.2	+51.9%
Customers, million	9.2	11.0	+19.7%
RAB per customer, June 2025 \$	7,000	8,868	+26.7%

Notes: * Each jurisdiction is measured in the final year before its first AER revenue determination and then aggregated; the customer-weighted benchmark date is approximately late 2009. † The 2025 NEM-only figures are calculated directly from the AER's October 2026 operational-performance workbook by subtracting Power and Water Corporation from the 14-DNSP total. The workbook reports actual RAB in June 2025 dollars and customer numbers in thousands. It also notes that the methodology used to determine customer numbers was modified for a number of DNSPs in the 2025 regulatory year to ensure consistent reporting, which may affect comparison with previous regulatory years. Sources: AER (2026b); author's calculations.

The AER's operational-performance workbook gives the 13 NEM DNSPs a 2025 actual distribution RAB of \$97.2 billion and 11 million customers, equivalent to \$8,868 per customer in June 2025 dollars. Relative to the

synthetic transfer benchmark, the real distribution RAB increased by 51.9 per cent after centralisation, while customer numbers increased by 19.7 per cent and so real RAB per customer by 26.7 per cent.

It is not suggested that this comparison establishes that centralisation necessarily caused higher capital intensity. Reliability and planning obligations, ownership, demand forecasts, network geography and asset age, technological change and, more recently, investment associated with consumer energy resources all affect the RAB. It does establish a narrower point relevant here: centralisation was not accompanied by an observable aggregate economy in the amount of regulated capital employed per customer. If part of the case for a national regulator rested on greater specialist expertise, consistent methods, benchmarking and economies of regulatory scale, the absence of such an aggregate pattern is relevant evidence even though it does not identify the counterfactual outcome under continued jurisdictional regulation (AER, 2026b).

How did regulated asset values, and normalized for growth in customer numbers and volumes distributed change during the period that the distributors were regulated by state commissions rather than the AER? Table 2 shows this for the five states in the NEM.

Table 2. Compound annual growth in real distribution RAB: state regulation and AER regulation (%)

Measure / regulator	NSW	Victoria	SA	Qld	Tasmania	RAB-weighted average
Real RAB — State	4.2	2.2	−0.2	9.1	4.7	5.0
Real RAB — AER	3.7	3.1	1.9	2.1	1.1	2.8
RAB/customer — State	2.8	0.5	−1.5	5.5	3.7	2.8
RAB/customer — AER	2.6	1.7	0.9	1.2	0.3	1.7
RAB/MWh — State	1.4	−0.3	−1.8	6.0	4.7	2.4
RAB/MWh — AER	4.3	3.4	2.5	2.4	0.9	3.2

(See end note for methodology and sources.)

Table 2 shows that across the five states, annual growth in total real RAB was approximately 5.0 per cent under the preceding state regulators and 2.8 per cent under the AER. However adjusted for growth in customer numbers and volumes distributed, the gap is much smaller: growth in real RAB per customer averaged 2.8 percent per year under state regulators and 1.7 per cent under the AER, while growth in real RAB per annual MWh distributed was higher in the AER period, at 3.2 per cent compared with 2.4 per cent under state regulation.

These are descriptive comparisons across different periods and should not be interpreted as estimates of the causal effect of regulatory centralisation. Comparison is complicated by the short period of jurisdictional regulation (typically just two five-year controls) and because the regulations in the second period were contemporaneous with design of the rules to be applied by the AER, for the treatment of outcomes, during the last period of jurisdictional regulation. The distributors in New South Wales, Queensland and Tasmania all overspent their jurisdictionally determined allowances, but the AER rolled that into their regulatory asset bases under rules that the AEMC had set. Who then effectively decided? Nevertheless these estimates suggest declining aggregate capital productivity under both state and AER regulation at similar rates when adjusted for changes in customer numbers and volumes distributed.

The AER's productivity evidence supports the finding of continuing declines in distribution productivity. Since 2014 the AER has published formal annual benchmarking reports, and its latest distribution report recalculates the series consistently across the 13 NEM DNSPs for 2006–24. Distribution-industry total factor productivity declined by an average 0.5 per cent a year over the full period. It declined by 1.2 per cent a year over 2006–15, recovered by 1.7 per cent a year over 2015–21, and then declined by an average 2.4 per cent a year from 2022. Productivity fell 3.8 per cent in 2024 and was 7.2 per cent below its 2021 level (AER, 2014, 2025b).

The decomposition is especially relevant to the political-economy argument. Operating-expenditure productivity shows substantial catch-up: between 2012 and 2021, reductions in opex helped 12 of the 13 DNSPs increase their opex partial productivity. Capital partial productivity tells a different story. The AER finds that relative capital productivity has consistently declined since 2006, with very little or no convergence among businesses; Evoenergy is the only DNSP whose capital productivity in 2024 was higher than in 2006. The problem examined here is therefore not merely one of operating cost. The national data reveal a persistent capital-accumulation issue of the kind that the ownership and planning-standard evidence would lead one to examine (AER, 2025b)¹.

The historical contrast is notable. Mountain and Littlechild (2010) found that benchmarking in Australia had been supported in principle but was then of limited practical consequence: the AER used benchmarking to test its bottom-up conclusions rather than set expenditure allowances, regarded it as a longer-term proposition, and relied heavily on bottom-up engineering reviews. The AER subsequently developed a much more systematic benchmarking programme and published its first annual distribution and transmission benchmarking reports in 2014. The ACCC later drew on the AER's evidence, observing in 2017 that network productivity had declined and that the decline was more pronounced in distribution; it also cited the Queensland Independent Review Panel's finding that privately owned Victorian and South Australian networks had consistently been more efficient than the state-owned networks in Queensland and New South Wales. There is consequently now enough evidence to ask a question that could not have been answered in 2010: did national regulation subsequently produce a visible aggregate productivity dividend? The AER's current series does not show one (Mountain and Littlechild, 2010; ACCC, 2017; AER, 2014, 2025b).

The AER notes that measured productivity can be affected by factors outside DNSPs' control, including jurisdictional obligations, weather and changing patterns of network use, while investment ahead of future demand and improvements in reliability, safety, environmental performance or service quality may not be fully captured in measured output. Rapid growth in rooftop solar can also reduce measured utilisation even though networks must continue to provide capacity at particular times. While these qualifications temper causal interpretation, they do not alter the descriptive result: neither real capital employed per customer or per MWh distributed nor the AER's measured productivity series reveals an obvious aggregate economic dividend from centralising distribution regulation.

6. The economics of distribution regulation increasingly favours decentralisation

6.1 Spillovers still favour wider regulation of transmission

The economics of regulatory geography begins with spillovers. Where the effects of a decision fall predominantly within one jurisdiction, local decision-making can reflect local conditions and preferences; where material effects cross boundaries, wider coordination is justified (Oates, 1999; Trillas, 2010). Electricity gives the distinction a clear application in the regulation of inter-state transmission compared to local distribution. A major interstate transmission line can change wholesale prices, generation opportunities and reliability across several regions. On the other hand a distribution feeder, local substation or flexibility contract principally affects users of a particular distribution system.

Distribution still has national interfaces, including technical standards, wholesale-market participation, data arrangements and some consumer or connection rules. Those interfaces justify common rules where cross-border consistency creates value. They do not establish that the aggregate revenue of geographically local distribution monopoly should be determined by one national regulator.

¹ Methodological note: only the AER's latest 2025 benchmarking series is used for the productivity comparison. The AER applies its updated output weights across the 2006–24 series and notes that output weights calculated in 2013 and 2018 were affected by coding errors; the discovery of the 2018 error led to re-estimation in 2020. It has also revised historical data definitions and capitalisation treatment. Earlier annual benchmarking reports should therefore not be spliced into the current series (AER, 2025b).

6.2 Electricity production is increasingly decentralized

The physical system has changed radically since the institutional settlement was designed. In 2005 only 1,406 small-scale solar PV systems were installed under the scheme recorded by the Clean Energy Regulator. By 31 August 2026 Australia had 4.53 million registered small-scale PV systems with 30.6 GW of rated capacity. By the end of 2024 rooftop solar already represented about 22 GW, or one quarter of NEM generation capacity, and supplied 14.7 per cent of total NEM generation in the first quarter of 2025 (Clean Energy Regulator, 2026; AER, 2025a).

The distribution system is consequently no longer simply the final delivery stage of centrally produced electricity. In the 2025 regulatory year, 3.1 million distribution customers, equal to 28 per cent of all DNSP customers, used export services. They exported 16.3 TWh, equal to 11 per cent of electricity delivered by distribution networks, before allowing for electricity generated and consumed behind the meter. Around 180,000 export customers used batteries, up 35 per cent in a year. The Clean Energy Regulator had recorded 510,949 battery systems eligible under the Small-scale Renewable Energy Scheme between 1 July 2025 and 31 August 2026, although that figure is not the complete stock of batteries installed before the programme began (AER, 2026a; Clean Energy Regulator, 2026).

These changes increase the local and behavioural component of distribution regulation. The effect of a battery, electric vehicle or rooftop system depends on location, tariff, export limits, control arrangements and customer behaviour. At the same time, state governments have again become prominent electricity planners through institutions such as VicGrid in Victoria and EnergyCo in New South Wales. Distribution has therefore become more heterogeneous at the same time that formal economic regulation has remained geographically centralised.

6.3 Electricity demand growth is highly uncertain and increasingly heterogeneous

AEMO's 2026 Electricity Statement of Opportunities projects that electricity consumed by data centres in the NEM will increase from approximately 5 TWh in 2025–26 to 34 TWh in 2035–36, raising their share of grid-supplied electricity from about 3 to 13 per cent. This is a substantial potential source of demand growth, but it is not a firm commitment to build or consume electricity. AEMO has revised its forecasting methods to allow for projects that do not proceed, differences between requested connection capacity and electricity actually used, and the gradual ramp-up of operating demand. Consequently, both the magnitude and timing of future load remain uncertain (AEMO, 2026a).

The uncertainty is also geographically concentrated. In Sydney, Ausgrid reports that it already serves 52 dedicated data centres and received more than 70 enquiries and applications in 2025 representing over 10 GW of prospective capacity. Yet its forecast is for more than 2 GW of connected data-centre load by 2040; it explicitly cautions that multiple enquiries may be competing for the same ultimate customer demand. In Western Sydney, Transgrid reported approximately 20 GW of enquiries for large electrical loads but only about 1.5 GW of capacity allocated under signed data-centre connection agreements as at August 2026. These figures measure different stages of project development and cannot be added together or treated as forecasts of actual load. They do, however, illustrate the extraordinary range between speculative proposals and committed connections in one part of the NEM (Ausgrid, 2025; Transgrid, 2026).

Comparable growth cannot be assumed for every distribution business. Large data centres are concentrated in Sydney and Melbourne, while the significance of new load elsewhere depends on particular industrial developments, local network capacity and whether projects connect to distribution or directly to transmission. Even within a single metropolitan area, an additional large customer can create an urgent need for augmentation at one substation while leaving capacity underutilised at another. The economically relevant uncertainty for a distributor is therefore not simply national annual TWh, but the probability, location, connection voltage, timing and operating profile of individual projects. National forecasts are useful for system planning but cannot substitute for that local assessment (AEMO, 2026a; Ausgrid, 2025).

This heterogeneity gives the question of regulatory geography a more concrete economic foundation than an appeal to decentralisation in the abstract. The investment error is asymmetric: failing to provide capacity for a credible large load may deter development, but building ahead of projects that are delayed, relocated or abandoned

can leave other customers financing underutilised regulated assets. Judgments about staged investment, customer financial commitments, cost allocation and alternatives to augmentation require detailed knowledge of local constraints and the credibility of particular proposals. At the same time, Western Sydney demonstrates that large distribution-connected loads can create upstream transmission constraints, which require coordination beyond an individual distribution area. The implication is not that all decisions should be local, but that decision-making should follow the geographical incidence of costs, benefits and information: coordinated national or regional treatment of material spillovers, and greater jurisdictional discretion over geographically specific distribution investment, subject to common disclosure and benchmarking (Transgrid, 2026; Oates, 1999; Trillas, 2010).

6.4 Knowledge and experimentation favours diversity

Hayek's problem of dispersed knowledge is increasingly relevant under these conditions. Some network information can be standardised and collected in a national database, but other knowledge emerges through interaction among networks, consumers, developers, local governments and new service providers. It is contextual, changes as participants respond to technology and prices, and is often discovered through experience rather than supplied in advance to a regulator (Hayek, 1945; Kirzner, 1997; Littlechild, 2014).

Institutional diversity can also generate information. One regulator can experiment sequentially, whereas several regulators can test alternative arrangements at the same time. A jurisdiction with unusually high battery penetration might adopt one approach to flexibility procurement while another tests connection charging, export services or expenditure incentives. Common data can then permit comparison of results. Ostrom's polycentric governance and Littlechild's treatment of competition as a discovery process both point to the possible value of such parallel experimentation where the preferred regulatory method is itself uncertain (Ostrom, 2010; Littlechild, 2014).

6.5 Scale economies are real but do not require one decision-maker

The strongest economic argument for centralisation is regulatory scale. Network regulation requires engineering, economics, finance, law, data and benchmarking expertise, so a larger regulator can sustain specialist teams and compare more businesses. International research confirms that regulator capability and the number of comparable firms condition the sophistication of benchmarking methods (Jamasp and Pollitt, 2000; Haney and Pollitt, 2011). These advantages attach primarily to information and expertise, however, and can be obtained through common regulatory accounts, shared datasets, joint procurement and specialist services without requiring one institution to make every final determination.

The available Australian staffing evidence also provides little indication of a large administrative saving from centralisation. Electricity-distribution licence fees represented about 26 per cent of Essential Services Commission expenditure in 2006–07 and 19 per cent in 2007–08. Applying those shares to Commission staffing and scaling the pooled Victorian estimate by distribution customer numbers gives an indicative pre-centralisation NEM total of about 45 to 60 FTE-equivalents, centred on 53. AER annual reports for 2012–18 allocated roughly 52 to 65 per cent of staff time to network regulation, equivalent to around 79 to 83 FTEs for all network regulation; plausible allocations across electricity distribution, transmission and gas imply about 45 to 56 FTE-equivalents for electricity distribution alone, before allowing for AEMC network rule-making (ESC, 2007–2009; AER, 2013–2018).

These estimates are necessarily rough because institutional functions changed and the AER also acquired responsibilities that did not sit with the former state regulators. They are therefore not evidence that centralisation increased administrative cost. Rather they are sufficient to reject a presumption that centralization offers staffing economies. Regulatory administration is also small relative to the asset and expenditure decisions influenced by regulation, so modest savings in agency costs would carry little weight if alternative institutional arrangements materially improved investment decisions, accountability or the speed with which regulatory errors are corrected.

7. Federal electricity systems compared: distribution regulation in Australia is an outlier

International evidence cannot determine which regulatory structure produces better outcomes in Australia because constitutional histories, ownership and industry structures differ too much for simple causal inference. It can

nevertheless test whether an integrated electricity market requires centralised distribution economic regulation. The answer is no: several large federal electricity systems integrate wholesale or interstate markets while leaving distribution economic regulation below the federal level.

The United States places most interstate transmission regulation with the Federal Energy Regulatory Commission while distribution remains predominantly under state or local regulation. India similarly combines a common national legislative framework and central regulation of interstate transmission with State Electricity Regulatory Commissions responsible for distribution and intrastate networks. Canadian provinces regulate distribution and much transmission despite extensive interconnection and cross-border trade, while Argentina also leaves most distribution regulation with provincial authorities. These arrangements differ greatly in detail but demonstrate that market integration and local monopoly regulation typically operate at different geographical levels.

Brazil is the clearest large-country counterexample because ANEEL regulates both transmission and distribution federally. Its constitutional history is different: federal responsibility for electricity services long predates the regulator and the modern market reforms. Brazil did not establish an integrated market with state distribution regulation and later conclude that market integration required transferring that function to the federal level. Germany supplies another useful variation, with common methodology coexisting with federal and Länder implementation. The lesson is not that Australia should copy another federation, but that harmonisation, shared information and market integration are typically institutionally separable from centralised regulatory control of distribution networks.

Australia is also an outlier in assigning detailed economic rule-making to a specialist institution separate from the regulator applying those rules. In all known comparators, regulatory design and implementation are located within the same organization. The comparison does not prove that the Australian model is inferior, but it reinforces the conclusion that it is an institutional choice shaped by Australia's federal settlement.

8. The apparent paradox: if state ownership is a problem, why decentralise?

The strongest objection to the proposal in this paper to re-decentralise distribution regulation is immediately evident: If government ownership can compromise regulatory independence, returning formal regulatory responsibility to governments that own distribution networks may appear to recreate the conflict that Parer had, perhaps, sought to escape. A simple return to the pre-2005 arrangements, with an owning government appointing its own regulator and no common information or external comparison, may risk reproducing the weaknesses identified by Parer and Mountain (2014, 2019). But on deeper consideration the argument is not so straightforward.

The present system does not remove those conflicts either. State governments remain capable of making reliability, resilience, planning and energy-policy decisions with material expenditure consequences, while the AER determines how efficiently those obligations are met and how costs enter regulated revenue. A state can therefore say correctly that revenue was approved by an independent national regulator, while the AER can say correctly that it must take jurisdictional policy obligations as given. The resulting division can make political and economic accountability less rather than more transparent.

Jurisdictional responsibility offers a potential advantage because it makes the connection between policy choice and regulatory consequence harder to obscure. If a government raises a reliability standard or directs planning that increases expenditure, the regulator in that jurisdiction might be expected to identify the incremental cost and the efficient means of satisfying it. The government would then bear clearer political responsibility for the trade-off. This is an accountability argument, not a claim that a state regulator is necessarily more independent than the AER/AEMC.

Appointment security, transparent models, public benchmarking, disclosure of government-mandated costs and credible review become especially important where the regulated business is government owned. Arguably state regulation makes such factors, and their possible absence, more clearly evident.

9. An alternative institutional settlement

How might re-decentralisation effectively proceed? This section identifies various aspects for further consideration.

9.1 Return formal distribution responsibility to jurisdictions

Formal responsibility for economic regulation of electricity distribution should return to participating jurisdictions, reversing the presumption established in the mid-2000s without dismantling the NEM. A jurisdiction should be free to use its existing independent economic regulator, establish a specialist energy regulator, share resources with another jurisdiction, or retain the AER under agreement. The choice of regulatory provider would itself become observable, comparable and revisable rather than fixed nationally.

Such an arrangement is different from recreating isolated state systems. Common market institutions would remain, while the supply of regulatory capability could be shared or contracted. Jurisdictions would recover clear responsibility for the local monopoly decision, but would not be required to duplicate every specialist function.

9.2 Preserve common information and benchmarking

Nationally comparable information is one of the genuine gains of the present framework and should be preserved. Common regulatory accounting, asset classifications, cost-allocation rules, service measures, reporting templates and data standards can reduce duplication and permit meaningful benchmarking. A jointly funded unit could maintain datasets and benchmarking tools and provide specialist analytical services to all regulators.

Jurisdictional regulators could then reach different expenditure, incentive and methodological judgments from the same comparable evidence. Common measurement would make those differences more informative rather than less. It would also restore a domestic benchmark for regulatory performance, allowing governments and customers to compare not only network businesses but the decisions of regulators themselves.

9.3 Make policy-driven network costs explicit

The reliability-standard experience suggests a further safeguard. Where a jurisdiction imposes a planning, reliability, resilience or other policy requirement that materially affects distribution costs, the requirement and its expected cost should be separately identified. The regulator should assess the efficient means of satisfying the policy even where it cannot alter the policy objective, and its determination should identify expenditure attributable to the jurisdictional decision where practicable.

Separating policy-driven costs would improve accountability. Consumers could see which costs followed from monopoly operation and which followed from an explicit governmental choice, while governments and regulators would have less scope to attribute the entire outcome to one another. The same disclosure would improve comparison across jurisdictions with different policy objectives.

9.4 Treat government ownership as a regulatory fact

Government-owned distributors should not be regulated on the basis that ownership is irrelevant. Their actual financing arrangements, shareholder objectives and governance incentives should be considered where economically material, and governments should disclose material directions and policy requirements affecting regulated expenditure. Competitive neutrality does not require regulators to assume that different ownership forms create identical incentives or financing conditions.

Where government ownership remains, arrangements for regulatory appointments and review should be especially transparent. The ownership function and energy-policy function should be institutionally distinguished where possible, and the regulator should publish enough information to make the financial consequences of government policy visible. No institutional arrangement removes political economy; the more realistic objective is to expose the relevant interests and incentives rather than conceal them behind a formal claim of regulatory independence.

9.5 Funding and accountability for the AER

If a jurisdiction elects to retain the AER for distribution regulation, it should fund the attributable cost of that service under a transparent agreement. Commonwealth appropriations should continue to support genuinely Commonwealth and NEM-wide responsibilities, but should not subsidise the AER as the default provider of a function that has formally returned to the states. Otherwise a Commonwealth-funded regulator would retain a structural advantage over state or shared alternatives and the reallocation of responsibility would be largely nominal.

Appointment and accountability arrangements would also need to distinguish the AER's national functions from distribution work performed for individual jurisdictions. The commissioning jurisdiction should have a clear role in defining the service and scrutinising its cost without compromising the independence of individual determinations.

9.6 Reconsider the boundary of AEMC rule-making

Re-decentralisation would require an explicit reconsideration of which distribution matters genuinely require National Electricity Rules. Rules necessary for wholesale-market operation, market-network interfaces, system security, common information standards and some connection arrangements have a clear NEM-wide rationale. Detailed methodology for determining the aggregate revenue of a geographically local distribution monopoly is different and should not be national merely because distribution regulation happened to be centralised.

As a starting presumption, detailed economic methodology should follow responsibility for the regulatory determination unless a demonstrable interstate or common-market benefit justifies a national rule. Jurisdictions retaining the AER could choose to retain common methodology, while others could allow their regulator greater discretion. The objective is not to abolish the AEMC but to distinguish rules needed for an integrated market from rules whose national status is a legacy of the 2003 settlement.

9.7 Transmission remains a different question

Major transmission investments can redistribute benefits and costs across regions and materially affect wholesale prices, generation investment and system reliability. Their economic geography therefore supplies a stronger rationale for NEM-level coordination and regulation. A differentiated institutional architecture, with wider regulation where spillovers are wider and more local regulation where effects are predominantly local will align regulatory geography with economic geography.

10. Discussion

Australia's national energy institutions are often presented as the culmination of a linear reform programme in which fragmented state systems gave way to a national market and national regulation followed naturally. The historical record suggests a more complicated process. The Commonwealth objective was understandable: National Competition Policy had challenged state barriers and inconsistencies, the ACCC had become an important national infrastructure institution, and multiple energy regulators created genuine transaction costs and uncertainty. Parer also correctly recognised the conflicts that can arise where governments own, regulate and make policy for electricity businesses.

A national market does not compel a national regulator for every monopoly function, however, and the Commonwealth had to negotiate the transfer of distribution regulation with states that initially resisted. The settlement divided institutional authority: the AER was placed in the ACCC framework but with substantial state involvement in governance; the AEMC was created separately under South Australian law with strong jurisdictional appointment rights; and states retained important ownership and policy powers. Bifurcation is therefore explicable as part of the institutional price of centralisation rather than merely an unusual technocratic design.

Subsequent experience shows why the incomplete character of centralisation is economically relevant. State decisions on reliability and planning contributed materially to the investment expansion, while the regulator responsible for revenues did not necessarily control those decisions. Ownership evidence likewise shows

markedly different outcomes between government and privately owned distributors. The aggregate evidence adds a further test. The synthetic transfer benchmark indicates that real distribution RAB per customer is now about 27 per cent higher than at transfer, while the AER's current benchmarking series shows aggregate total factor productivity declining over 2006–24 and a persistent decline in capital productivity. While these observations do not identify the causal effect of national regulation, they do suggest no visible aggregate productivity dividend from centralisation. Formal price regulation was centralised without eliminating the underlying policy and ownership incentives and without producing an obvious economy in the use of capital (Mountain, 2014, 2019; AER, 2025b, 2026b; author's calculations).

Technological change has altered the balance further. Millions of households and businesses now produce, consume, store and export electricity through distribution networks, and rooftop solar alone has become the largest category of generation capacity in the NEM. The information relevant to distribution is consequently more locational and behavioural than it was when the federal bargain was negotiated. State planning roles have also expanded again. A regulatory system designed around greater national uniformity now operates over an electricity system that is becoming more heterogeneous at the local level.

The strongest counterarguments remain scale and independence. Small regulators can lack expertise, and an owning state can compromise regulation. The proposed model addresses the first through common information, shared specialist services and the option to retain the AER, and addresses the second through institutional arrangements that make ownership and state policy costs explicit rather than assuming that centralisation has removed them. The historical staffing comparison also suggests that the assumed administrative economy from centralisation is not evident.

Regulatory diversity creates some uncertainty, but it also produces information. There is a difference between inconsistent data and different judgments. Inconsistent data impede comparison and should be minimised; different judgments can reveal which methods work under different conditions. A system facing technological and behavioural uncertainty should not automatically prefer a uniform regulatory mistake to observable diversity.

11. Conclusion

Australia's centralisation of electricity distribution regulation was not the application of an established economic principle that one market requires one regulator. It arose from a particular period of National Competition Policy, a Commonwealth ambition to make energy regulation genuinely national. This ambition reflected legitimate concerns about fragmented regulation and government conflicts of interest. But it resulted in bargaining with states reluctant to surrender jurisdiction. The settlement divided authority: formal revenue regulation moved to the AER, detailed rule-making went to the AEMC, and the states retained important roles in national governance as well as ownership, planning and other policy functions.

The consequences are visible in the subsequent record. Jurisdictional reliability and planning decisions contributed materially to the network investment expansion, while government-owned networks accumulated substantially higher asset and revenue outcomes compared to their privately owned peers. At the aggregate level, the synthetic transfer comparison suggests that real distribution RAB per customer is now about 27 per cent higher than when regulation transferred, while the AER's current benchmarking estimates show total factor productivity declining over 2006–24 and a persistent decline in capital productivity. While this does not prove that national regulation caused excessive investment or falling productivity, it does show that centralisation did not abolish the political and policy incentives shaping network expenditure and did not produce an observable aggregate productivity dividend. In addition, the administrative scale economy from placing all distribution determinations in one institution is not readily visible.

The electricity system has since changed profoundly. Production is now far more decentralised, with millions of customers owning generation and storage and almost three in ten distribution customers exporting surplus electricity to the grid. Local information, consumer behaviour and state planning increasingly shape network needs. Common data, benchmarking and specialist expertise remain valuable, but those benefits do not require common final decision authority.

Formal responsibility for distribution economic regulation should therefore return to participating jurisdictions. States should be free to retain the AER and pay for its services, use an independent state regulator or share regulatory capability in some other way. State-imposed policy costs should be transparently identified, common accounting and information should be retained, and detailed distribution methodology should be national only where a national benefit can be demonstrated. Transmission should remain a separate question because its interstate effects are materially wider.

The Australian experience is relevant elsewhere. The decentralization of distribution network regulation is likely to clarify responsibility and improve learning. This is particularly important in the context of rapid technology change, demand-side uncertainty and having regard to the evidence that suggests centralisation has failed to achieve the claims made of it.

Methodological endnote: five-state RAB growth comparison

The calculations use the distribution regulated asset bases, customer numbers and annual electricity delivered for NSW (Ausgrid, Endeavour Energy and Essential Energy), Victoria (CitiPower, Powercor, Jemena, United Energy and AusNet), South Australia (SA Power Networks/ETSA Utilities), Queensland (Energex and Ergon Energy), and Tasmania (Aurora Distribution/TasNetworks). The principal source families are original determinations of IPART, the Victorian Office of the Regulator-General and Essential Services Commission, ESCOSA, the Queensland Competition Authority and the Tasmanian economic regulator, together with AER distribution determinations, network performance reports and the 2026 operational data workbook (AER, 2026a, 2026b).

RAB values are expressed in approximately June 2025 dollars using Australian CPI conversions. RAB per customer equals real RAB divided by distribution connections; RAB per MWh equals real RAB divided by annual MWh delivered through distribution networks. For each measure, the ratio of the closing to opening observation is converted to a compound annual rate over the relevant period. The five-state mean is the arithmetic weighted mean of these annual state rates, with weights equal to the real opening RAB in the corresponding state or AER period; it is not the compound growth rate of a pooled asset base.

The comparison uses NSW 1999–2009 and 2009–2025; Victoria approximately 2001–2010 and 2011–2025; South Australia and Queensland 2005–2010 and 2010–2025; and Tasmania January 2008–June 2012 and July 2012–June 2025. The dates reflect successive jurisdictional transfers to the AER rather than a common calendar-year cut-off.

Where exact annual observations could not be confirmed, the closest documented year, regulator forecast or historical estimate was used. NSW opening GWh uses a 1997–98 observation as a proxy for 1998–99 and recent GWh comes from a secondary compilation. Victoria's 2001 opening RAB uses a historical reported-asset proxy rather than the original ORG regulatory opening valuation; its historical customer numbers and recent GWh are partly estimated. South Australia's opening customer count is estimated and the 2010 RAB adjustment requires reconciliation; its 2025 GWh uses SA Power Networks' documented 10,418 GWh forecast rather than an actual return. Queensland historical customers and delivery volumes are partly approximated, and recent RAB is based on the nearest rounded observation. Tasmania uses nearby-year historical customer and energy volumes; its 2024–25 delivery of 4,608 GWh is directly reported by the Tasmanian Economic Regulator. Several 2025 RAB observations use June 2024 values adjusted approximately to 2025 prices.

The rates are consequently indicative rather than fully audited. They should not be read as a causal estimate of the effects of centralisation, since the regulatory periods differ in duration and economic conditions, and network obligations, ownership, demand, rooftop solar and reporting definitions changed. Rates and weighted averages are calculated before rounding and displayed to one decimal place.

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