

**Are electricity network investment regulatory
processes fit-for-purpose in Australia?
Comparative Synthesis of International Network
Investment Regulation**



Final report

RACE for Networks

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Are electricity network investment regulatory processes fit-for-purpose in Australia? A review

Comparative Synthesis of International Network Investment Regulation

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Project partners



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What is RACE for 2030?

[RACE for 2030](#) is a 10-year cooperative research centre (CRC) with \$350 million of resources to fund and support research towards a reliable, affordable, and clean energy future.

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Executive Summary

This review compares how five jurisdictions – the United States, Great Britain, Germany, the Netherlands and Australia – regulate electricity distribution network investment, with additional reference to France, Norway and Sweden where the literature makes use of them. It is intended to sit alongside our companion report on Australian distribution network investment regulation (Csereklyei and Kallies, 2026), providing the international comparative context needed to assess which features of the Australian framework are common practice, genuine outliers, or design choices other jurisdictions have already tested, refined or abandoned.

The review treats investment regulation as analytically distinct from operating-cost regulation, given the long-lived, largely irreversible nature of network investment. It adopts a hierarchical comparative framework distinguishing the fundamental choice of regulatory model, the detailed design of incentive regulation where adopted, the specific instruments used to shape investment incentives, and the governance procedures used to test and approve investment – alongside the institutional and legal context in which regulation sits and the allocation of risk and remuneration between networks and consumers.

Four principal findings emerge from the comparison:

- **Regulatory design is strongly context-dependent.** Constitutional and legal starting points, the number of firms a jurisdiction regulates, path dependency from a small number of influential early reforms (notably Great Britain’s 1990 privatisation and subsequent RIIO reforms), and EU legal integration each help explain why jurisdictions facing broadly similar engineering and economic problems have arrived at materially different regulatory designs.
- **Institutional setting constrains, but does not determine, regulatory choice.** Federalism, ownership structure and market structure shape which instruments are administratively or statistically viable, but do not straightforwardly predict which regulatory model a jurisdiction adopts.
- **Effectiveness is a property of implementation, not of a regulatory label.** Great Britain’s TOTEX reform and Sweden’s revenue-cap experience both illustrate that a design’s real-world outcomes depend on how faithfully it is implemented, not on the model it is nominally described as. Australia’s own incentive framework – notably the growing gap between the CESS and EBSS sharing ratios – offers direct evidence of a design that has produced uncoordinated, scheme-by-scheme outcomes rather than a harmonised result.
- **Path dependency can be overcome.** Germany, the Netherlands and Great Britain have each made fundamental structural changes to their investment regulation over the review period, generally enabled by regulatory frameworks that are less detailed and prescriptive than Australia’s National Electricity Rules, which gives their regulators greater flexibility to adapt as conditions change.

For the design of the NEM's own investment frameworks, the review's comparative evidence points to the value of flexibility under transition conditions, evidence that path dependency is not immutable. A more conceptual redesign, informed by comparative experience, rather than a incremental change, is recommended.

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1. Introduction

Electricity distribution networks are facing an unusually demanding investment task over the coming decades: accommodating electrification, distributed energy resources and decarbonisation policy, while continuing to meet long-standing obligations around reliability, safety and affordability. How a jurisdiction regulates network investment – what it rewards, what it penalises, and what discretion it leaves to the network operator, the regulator and third parties – shapes both the cost consumers ultimately bear and the pace and quality of the transition itself. This review compares how five jurisdictions – the United States, Great Britain, Germany, the Netherlands and Australia – answer that question, with additional reference to France, Norway and Sweden where the literature makes references.¹

This comparative review’s literature corpus was assembled through a structured but not systematic search: sources were drawn from peer-reviewed journal articles, regulatory decisions and consultation documents, and major research reports (including chapters from the forthcoming Handbook on Electricity Regulation, Glachant, Joskow and Pollitt, 2025) identified through targeted searching by jurisdiction and topic, supplemented by sources known to the authors from prior work in this field. The jurisdictions compared in depth – Great Britain, Germany, the Netherlands and Australia – were selected because their distribution networks are separately and independently regulated rather than vertically integrated with generation or retail, making their investment regulation directly comparable to the unbundled Australian NEM context. These jurisdictions represent a spread of federal and unitary systems with mature, well-documented regulatory and incentive-regulation regimes.

Additionally, we reference regulation in effect in the United States France, Norway and Sweden where applicable and literature was available.

Coverage across these jurisdictions is not uniform. Some jurisdictions – particularly Great Britain and, to a lesser extent, Australia – are represented by a larger and more granular literature, including detailed regulatory decisions and sector-specific commentary, while coverage of others reflects a comparatively thinner published record. This asymmetry reflects the underlying availability of English-language academic and regulatory material at the time of drafting, rather than a judgement about the relative importance or complexity of any jurisdiction’s regulatory framework, and readers drawing cross-country conclusions should bear this asymmetry in mind.

This review is intended to sit alongside our first report in this project (Csereklyei and Kallies, 2026), providing the international comparative context needed to assess which features of the Australian framework are common practice, which are genuine outliers, and which represent

¹ This review’s comparative focus is on the United States, Great Britain, Germany, the Netherlands and Australia, selected to reflect the depth of literature and primary sources available at the time of drafting. Other jurisdictions – including France, Norway and Sweden – are referred to throughout where the literature reviewed makes reference to them, most often in the course of comparative tables or studies compiled by others, but are not treated as standalone case studies in their own right.

design choices other jurisdictions have already tested, refined or abandoned. Where we are making reference to the Australian electricity market legal and governance framework in this report, the reference is to the Australian NEM.

Investment regulation is treated throughout this review as analytically distinct from the regulation of day-to-day operating costs, for reasons set out in detail in Section 2: network investment is long-lived, largely irreversible, and recovered over a time horizon that outlasts any single regulatory control period, which creates a set of commitment, information and risk-allocation problems that operating cost regulation does not share. The review's structure follows from this starting point, adopting a hierarchical framework that distinguishes four analytically separate layers of regulatory design – the fundamental choice of regulatory model (Section 4), the detailed design of incentive regulation where adopted (Section 5), the specific instruments used to shape investment incentives (Section 6), and the governance procedures used to test and approve investment (Section 7) – alongside two cross-cutting dimensions that condition how those four layers actually operate in practice: the institutional and legal context in which regulation sits (Section 3) and the allocation of risk and remuneration between networks and consumers (Section 8). Section 9 examines a specific and increasingly important instrument for managing investment uncertainty – the use of third-party and non-network solutions in place of conventional network augmentation – that cuts across several of the preceding layers. Section 10 draws these threads together into a comparative synthesis.

This structure reflects a deliberate choice, discussed further in Section 2.4, to keep regulatory philosophy, regulatory model, regulatory instruments and investment governance analytically separate, even where the literature or a particular jurisdiction's practice blurs the boundaries between them. Several such boundary-blurring cases recur throughout the review – the United States' combination of cost-of-service and performance-based regulation, Australia's building-block model's simultaneous resemblance to rate-of-return and incentive regulation, and Germany's recent shift from government ordinance to independent regulatory decision-making – and rather than forcing these cases into a single category, the review treats the degree and form of hybridity itself as a comparative variable worth tracking.

2. Conceptual Framework

2.1 Why investment regulation differs from operational regulation

Economic regulation of electricity networks has traditionally treated operating expenditure and capital expenditure as governed by the same underlying logic: both are costs a regulated monopolist incurs, both must be recovered through allowed revenues.

Investment decisions, however, raise a distinct set of regulatory problems that operational cost control does not. This is because investment decisions differ from operating decisions along three dimensions: the timeframe over which their costs are recovered, the type of protection regulation is expected to provide, and the point in time at which the regulator can know whether the decision was actually a good one. Each of these three differences is set out in turn below. First, investment decisions are largely irreversible and their consequences are recovered over time horizons that greatly exceed the length of any single regulatory control period. A distribution network's assets typically have useful lives of thirty years (Simshauser and Akimov, 2019), while allowed revenues are reset every three to eight years depending on the jurisdiction (Kuiper, 2024).

Simshauser and Akimov (2019) note that unless regulatory commitment is credible, capital markets will price in the risk of *ex post* opportunism, raising the cost of capital and distorting future investment incentives.

Second, the goals of regulation with respect to capital investment are explicitly protective in a way that operational cost regulation is not. Joskow and Schmalensee (2025, p 47) identify the core purposes of network regulation as including not only the mitigation of monopoly power, but also “protection of investors in the regulated enterprise from *ex post* expropriation of the associated long-lived assets in order to preserve investment incentives.” This second objective – safeguarding the firm's ability to recover sunk investment – has no direct analogue in the regulation of day-to-day operating costs, which are neither sunk nor asset-specific in the same sense.

Third, investment and operating decisions differ in the type and timing of information available to the regulator. Operating efficiency can, in principle, be assessed through benchmarking against comparable firms within a single period (Bjørndal et al., 2018). Investment efficiency, however, depends on judgments about whether a project was genuinely needed and correctly sized – judgments that in many cases can only be made with confidence years after the fact, once demand, technology costs and policy settings have played out. This is why investment regulation typically relies on a distinct toolkit that operational regulation does not require: *ex ante* cost-benefit tests, prudency reviews, contingent project mechanisms and *ex post* efficiency reconciliation schemes. The Australian regulatory investment test for distribution (RIT-D), for instance, requires network businesses to identify an investment need as the objective the network seeks to achieve when investing in the network rather than technology terms, evaluate credible options including non-network alternatives, and select whichever option maximises net economic benefit – a forward-looking, option-based process with no equivalent in the annual assessment of operating cost efficiency (Csereklyei and Kallies, 2026). Because the true need for many projects

only becomes apparent once construction is under way or demand materialises, most systems also provide separate mechanisms – contingent projects, cost pass-throughs, and reopeners – to accommodate investment needs that could not reasonably have been forecast in advance (Csereklyei and Kallies, 2026).

Together, these three features – long-lived and largely sunk cost recovery, an explicit protective rationale, and information that resolves only slowly over time – explain why almost every jurisdiction we examine in this review regulates investment through separate instruments from those used for operating costs, even where both are nominally governed by the same overarching regulatory model.

2.2 Characteristics of network investment

The distinctive treatment of network investment reflects underlying characteristics of the investment itself, which recur throughout the literature.

Natural monopoly and scale economies: Electricity distribution networks are the standard textbook example of natural monopoly: the entire demand within a given area can be served at lowest cost by a single network rather than by competing, duplicative networks (Posner, 1969). Because duplicating physical network infrastructure to enable competition would impose large and unnecessary costs on consumers, regulation is generally preferred to competition as the discipline on prices and investment (Joskow and Schmalensee, 2025).

Capital intensity, sunk costs and asset specificity: Distribution networks require very large upfront capital outlays relative to their ongoing operating costs, and the resulting assets – poles, wires, substations, transformers – have little or no alternative use outside network service. Long-lived sunk costs of this kind represent a large share of total network costs (Joskow and Schmalensee, 2025), and once committed, this capital cannot be redeployed if demand or policy conditions change.

Lumpiness and indivisibility: Unlike many operating costs, network investments frequently cannot be scaled continuously to match demand; capacity is added in discrete increments (a new substation, a reinforced feeder), so investment timing and sizing decisions involve real trade-offs between under- and over-building relative to smoothly growing demand.

Demand, technology and policy uncertainty over long asset lives: Because assets are held for decades, investment decisions must be made against forecasts of demand, distributed energy resource uptake, electrification and decarbonisation policy that are inherently uncertain and that networks in the current transition increasingly find difficult to model with confidence. This uncertainty is compounded where investment planning and revenue determination processes are only weakly linked to system-wide, economy-level planning scenarios – for example, national transmission or system-operator planning – producing risks of misalignment between network-level investment and the broader decarbonisation pathway (Csereklyei and Kallies, 2026).

Interdependence and system-level obligations: Network investment decisions are rarely independent of one another or of the wider power system: a distribution network's expenditure interacts with generation siting, transmission planning and, increasingly, the connection of distributed energy resources. At the same time, electricity is an essential service, and networks carry an ongoing statutory obligation to invest in maintaining safe, secure and reliable supply, regardless of the commercial attractiveness of any individual project (Csereklyei and Kallies, 2026).

Empirically, these characteristics also shape how investment responds to regulatory design: Using a panel of Norwegian distribution companies, Poudineh and Jamasb (2016) find that network investment is driven primarily by the prior period's investment rate, the socio-economic cost of energy not supplied, and the remaining useful life of existing assets – that is, largely by the physical and reliability characteristics of the asset base itself, with only partial responsiveness to the incentive mechanisms regulators design to influence investment timing and level.

2.3 Objectives of investment regulation

The literature converges on a recurring, if not always fully reconciled, set of objectives that investment regulation is expected to achieve.

Efficient investment level

The central and most frequently stated objective is to secure an efficient quantum of investment: enough to maintain safety, reliability and capacity, but no more than is economically justified. Because regulated firms earning a return on their asset base may have an incentive to over-invest in capital relative to more efficient combinations of capital and other inputs – the classic Averch-Johnson effect – much of investment regulation is designed specifically to guard against capital bias and “gold-plating” (Csereklyei and Kallies, 2026). Equally, regulators must guard against the opposite failure of systematic under-investment that would compromise reliability (Poudineh and Jamasb, 2016).

Cost recovery and financeability

A regulatory regime must give the firm a reasonable opportunity to recover efficiently incurred capital and operating costs, including a return commensurate with its cost of capital, or private capital will not be forthcoming. Joskow (2024) frames this as a participation constraint: without a credible expectation of cost recovery over the life of the investment, private firms will not invest, regardless of how the incentive component of a scheme is designed.

Regulatory commitment and stability and financial predictability is therefore itself treated in the literature as an objective, not merely a design constraint – a point with direct relevance for the Comparative Synthesis, since jurisdictions differ markedly in how much discretion their regulators retain to revisit past investment decisions.

Static and dynamic efficiency, including CAPEX/OPEX neutrality

Beyond the efficient level of investment, regulation is expected to promote productive efficiency in how investment is delivered, and dynamic efficiency in the sense of encouraging innovation and the optimal balance between operating and capital expenditure where this lowers overall system cost – for example, the use of third-party or non-network services in place of new capital works.

Accommodating the energy transition

More recently, jurisdictions have layered additional objectives onto investment regulation in response to decarbonisation: accommodating rapid growth in distributed energy resources and electrification seeking to avoid both under-investment (which would constrain the transition) and over-investment (which would burden consumers with costs from a system that may evolve differently than forecast), and encouraging flexibility and non-network alternatives ahead of conventional network reinforcement

Australia's National Electricity Objective illustrates how these goals can be formally combined: the National Electricity Law directs the promotion of efficient investment in, and efficient operation and use of, electricity services in the long-term interests of consumers, with respect to price, quality, reliability and security of supply, the reliability, safety and security of the national electricity system; and the achievement of jurisdictional greenhouse gas reduction targets (NEL s7).

Consumer protection

Underlying all of the above is the basic regulatory purpose of protecting consumers, who ultimately bear the cost of network investment through their bills, from also paying for the majority of investments that may be deemed imprudent or inefficiently delivered (Csereklyei and Kallies, 2026).

Formal statutory expression of these objectives

Each jurisdiction in this review expresses some version of the objectives above in binding legal text, though the four statutory formulations differ markedly in structure. Germany's *Energy Industry Act* (Energiewirtschaftsgesetz (EnWG)) §1(1) states the purpose of the Act as the most secure, affordable, consumer-friendly, efficient, environmentally sound and greenhouse-gas-neutral supply of electricity, gas and hydrogen practicable, increasingly based on renewable energy. EnWG §1(2) then provides a separate, specific objective for network regulation itself: securing effective and undistorted competition in electricity and gas supply, securing long-term capable and reliable network operation, and achieving a macroeconomically optimised energy supply, with regulation required to take into account forward-looking network expansion and digitalisation, renewable generation and hydrogen use, system flexibilisation, and an appropriate distribution of network costs associated with renewable generation build-out ².

² Original German (EnWG §1(1)–(2)): „(1) Zweck des Gesetzes ist eine möglichst sichere, preisgünstige, verbraucherfreundliche, effiziente, umweltverträgliche und treibhausgasneutrale leitungsgebundene Versorgung der Allgemeinheit mit Elektrizität, Gas und Wasserstoff, die zunehmend auf erneuerbaren Energien beruht. (2) Die

Great Britain's *Electricity Act 1989*, as amended, states a single principal objective for the Secretary of State and the Office of Gas and Electricity Markets (Ofgem): to protect the interests of existing and future consumers. These interests are defined to include their interest in the Secretary of State's compliance with the UK's statutory net zero and carbon budget duties under the *Climate Change Act 2008*, their interest in security of electricity supply, and their interest in the fulfilment of designated regulatory objectives – with that principal objective to be pursued, wherever appropriate, by promoting effective competition (*Electricity Act 1989*, s.3A).

The Netherlands' *Energiewet 2026* takes a third approach again, directing the ACM, in exercising its powers, to have regard to Article 58 of EU Directive 2019/944, which sets out the general objectives of national regulatory authorities across the Union: promoting a competitive, secure and environmentally sustainable internal electricity market; achieving, in the most cost-effective way, secure, reliable and efficient non-discriminatory systems that are consumer-oriented; ensuring system operators and users face appropriate short- and long-term efficiency incentives; and helping to secure high standards of universal and public service, including protection of vulnerable customers (*Energiewet 2026*, art.5.1(4); Directive 2019/944, art.58)³.

Read together, these texts share a recognisable core – security/reliability of supply, cost-effectiveness or efficiency, and consumer protection recur in some form in all of them – but differ in how explicitly they name competition objectives in their own right or whether competition is named as the means to pursue overall objectives. While the Australian and German, and to a lesser degree Dutch regulatory objectives, see competition as stand alone objectives, the British objective clauses treat competition as a means to pursue consumer interests.

2.4 Analytical framework used for comparison

These conceptual foundations point to a recurring difficulty in comparing investment regulation across jurisdictions: regulatory instruments that appear similar on the surface often serve different combinations of the objectives set out above, and instruments that are formally distinct are frequently combined in practice rather than adopted as pure alternatives (Joskow, 2024). Any comparative framework must therefore be explicit about the level of the regulatory system at which a given feature operates, so that, for instance, a country's choice of revenue-setting mechanism is not conflated with its choice of investment governance procedure.

Regulierung der Elektrizitäts- und Gasversorgungsnetze dient den Zielen der Sicherstellung eines wirksamen und unverfälschten Wettbewerbs bei der Versorgung mit Elektrizität und Gas, der Sicherung eines langfristig angelegten leistungsfähigen und zuverlässigen Betriebs von Energieversorgungsnetzen sowie der gesamtwirtschaftlich optimierten Energieversorgung. Zur Verfolgung der Ziele in Absatz 1 berücksichtigt die Regulierung insbesondere 1. den vorausschauenden Ausbau, die optimierte Nutzung und die Digitalisierung der Energieversorgungsnetze, 2. die Erzeugung und Nutzung von Strom aus erneuerbaren Energien und Wasserstoff, 3. die Flexibilisierung im Elektrizitätssystem, einschließlich der Nutzung von Energiespeichern sowie 4. eine angemessene Verteilung der Netzkosten im Zusammenhang mit dem Ausbau der Stromerzeugung aus erneuerbaren Energien.“

³ Original Dutch (*Energiewet 2026*, art.5.1(4)): „De Autoriteit Consument en Markt houdt bij de uitoefening van de haar bij of krachtens deze wet toegekende taken en bevoegdheden rekening met artikel 40 van richtlijn 2009/73 en artikel 58 van richtlijn 2019/944.“

This review adopts the hierarchical structure set out in Section 1. For each jurisdiction, the comparison will draw out: (i) the legal and institutional foundation of investment regulation; (ii) the regulatory model and its incentive design; (iii) the specific instruments used to shape the level, timing and composition of investment; (iv) the governance procedures used to test and approve investment *ex ante* and to review it *ex post*; (v) how investment risk is allocated between the network and consumers; and (vi) the observed outcomes, where the literature permits assessment – in particular, evidence of persistent over- or under-investment, and the extent to which the regime has adapted to the additional demands of decarbonisation.

We anticipate, and will flag explicitly rather than suppress, cases that blur the hierarchy adopted here – Joskow (2024) notes that notably the US, cost-of-service regulation and performance-based regulation should be viewed as complements rather than substitutes, so that a single jurisdiction may combine features drawn from more than one branch of the hierarchy simultaneously. Rather than forcing such cases into a single category, the review will note where a jurisdiction’s practice sits across more than one node of the hierarchy, so that one can assess whether the boundary-blurring itself is systematic and informative, rather than a shortcoming of the classification.

3. Institutional and Governance Frameworks

3.1 Regulatory institutions and legal foundations

Every jurisdiction in this review regulates network investment through a specialist economic regulator operating under dedicated sector legislation, but the institutional form of that regulator, and the legal instrument through which it acts, differ markedly.

In the United States, regulatory authority over electricity distribution rests with state public utility commissions, which set allowed revenues, profitability and retail tariffs for utilities under state law, while the Federal Energy Regulatory Commission (FERC) regulates interstate transmission service under federal law (Joskow and Schmalensee, 2025). There is no single national distribution regulator; each state commission operates under its own statutory mandate, and the degree to which performance-based regulation has been layered onto traditional cost-of-service regulation varies state by state (Joskow, 2024).

In Great Britain, distribution network operators have been regulated by a single national regulator since privatisation in 1990, originally the Office of the Electricity Regulator (Offer, created 1989) and, since 1998, the Office of Gas and Electricity Markets (Jenkins, 2025). Network regulation is exerted through price control conditions set through a company's operating licence, licence modifications are consulted on before being imposed, and a Distribution Network Operator (or, since 2012, a third-party licensed energy company) can appeal a price control decision to the Competition and Markets Authority. Ofgem is separately accountable to the UK Parliament and subject to judicial review and National Audit Office scrutiny (Jenkins, 2025).

Germany's institutional framework has recently undergone fundamental legal change. Network tariffs and revenue caps were historically set through government ordinances – principally the Incentive Regulation Ordinance (Anreizregulierungsverordnung, ARegV) and the Electricity and Gas Network Tariff Ordinances (StromNEV/GasNEV) – rather than through case-by-case regulatory decisions. On 2 September 2021, the Court of Justice of the European Union held, in Case C-718/18 (European Commission v Federal Republic of Germany), that Germany had failed to properly transpose several provisions of Directive 2009/72/EC (electricity) and the equivalent gas directive concerning the exclusive competencies of national regulatory authorities – specifically including Article 37(1)(a) and (6)(a)-(b), which require the national regulatory authority itself, rather than government, to fix or approve the methodologies used to calculate or establish transmission and distribution tariffs (Case C-718/18, operative part). In response, Germany amended its Energy Industry Act (Energiewirtschaftsgesetz, EnWG) to transfer this power to the Federal Network Agency (Bundesnetzagentur, BNetzA), acting through a newly created Grand Ruling Chamber for Energy (Große Beschlusskammer Energie). That chamber's decision establishing the new regulatory framework and incentive regulation methodology for electricity distribution network operators ("RAMEN Strom"), issued under EnWG §29 in conjunction with §§21 and 21a, confirms that incentive regulation will begin its fifth regulatory period on 1 January 2029 with a 2026 base year, and that this and future regulatory periods will run three years rather

than the five years used previously (Bundesnetzagentur, 2025, §2). In other words, governance by government ordinance has been replaced by decision-making by the independent regulator itself.

In the Netherlands, network regulation is the responsibility of the national competition and markets authority, the Autoriteit Consument & Markt (ACM), operating until recently under the Electricity Act 1998 (Elektriciteitswet 1998), now replaced with the *Electricity Act 2026* (Energiewet 2026). The ACM has regulated distribution system operators (DSOs) through successive price control review periods since 2000, based on a framework of yardstick competition rather than firm-specific cost assessment (Nillesen and Pollitt, 2026), although this is changing now to cost based regulation (Brunekreeft, 2025).

Australia's institutional framework is distinctive in being an intergovernmental scheme rather than a single national or state-based system. The National Electricity Market (NEM), established in 1996 under the National Electricity Law (given effect through the *National Electricity (South Australia) Act 1996* (SA) and mirrored through enabling legislation in each participating state), operates through four separate national bodies: a Ministerial Council of state and federal energy ministers, which sets strategic policy direction; the Australian Energy Market Commission (AEMC), which makes the detailed National Electricity Rules (NER); the Australian Energy Regulator (AER), which enforces the NER and regulates network revenues; and the Australian Energy Market Operator (AEMO), which operates the wholesale market and undertakes system and transmission planning (Csereklyei and Kallies, 2026). In the context of network regulation, the central institutions are the AER, as the body administering network regulation and the AEMC, as the body developing the rules for network regulation (although the rules give the AER considerable power to develop guidances around incentive regulatory schemes). This split between regulator and rule maker is unusual compared to the comparative jurisdictions.

3.2 Depth and scope of regulation

The number and average size of regulated entities varies enormously across jurisdictions, with consequences for how detailed and firm-specific regulatory scrutiny can practically be. Germany's distribution sector is among the most dispersed in the world, with more than 800 distribution system operators, ranging from around 20 large companies to a very large number of small, often municipally owned local utilities (Stadtwerke) (Brandstätt and Glachant, 2025). Great Britain, by contrast, has just 14 regional distribution network operators covering the whole of Great Britain (Jenkins, 2025), and Australia has a similarly small number of distribution network service providers, typically one to several per state (Csereklyei and Kallies, 2026).

The intensity of information and documentation requirements imposed on regulated firms also varies with scope. In Australia, distribution networks face extensive, prescriptive documentation obligations spanning both physical network planning (an annual Distribution Annual Planning Report under Chapter 5 of the NER – soon to shift to an 5-yearly Distribution Network Development with annual updates) and economic forecasting (a five-year revenue proposal under Chapter 6), with many of these requirements linked to statutory penalty provisions (Csereklyei and Kallies, 2026). In Germany, the shift from ordinance-based to case-by-case regulatory

determination under the RAMEN Strom reform is explicitly intended to allow the BNetzA more scope to tailor the depth of scrutiny – for example, differentiating adjustment mechanisms for standard and simplified benchmarking procedures depending on operator size (Bundesnetzagentur, 2025).

3.3 Federalism and allocation of regulatory responsibilities

In federated states, network regulatory frameworks can be located at sub-national (state) level, national level, or may rely on an intergovernmental approach. This determines the homogeneity or heterogeneity of approaches to network regulation in a nation state. As will be seen, apart from the US, the general shift is towards a homogenous whole of country framework for network regulation.

The United States exhibits genuine constitutional federalism: distribution regulation is a state responsibility exercised by fifty separate public utility commissions under state law, while FERC's jurisdiction over interstate transmission is entirely separate and federally derived (Joskow and Schmalensee, 2025; Joskow, 2024). This produces substantial heterogeneity in investment regulation across states, since there is no requirement for state commissions to adopt common approaches, and the pace of adoption of performance-based regulation has consequently varied widely by state (Joskow, 2024).

Australia starts from a similar constitutional basis of energy law being state responsibility. However, Australia adopted a cooperative federalism model achieved through intergovernmental agreement. As a result, the NEM's national framework exists only because each participating state has separately enacted legislation applying the National Electricity Law within its own jurisdiction, coordinated through a Ministerial Council of state and federal energy ministers (Csereklyei and Kallies, 2026). This gives the NEM a genuinely national rulebook (the NER) and a single national regulator (the AER) for participating states, but the arrangement remains dependent on continuing intergovernmental agreement rather than federal constitutional authority.

Germany similarly has a federal structure. Unlike in Australia, the German Constitution (Basic Law) allows the federal parliament to make laws for the economic regulation of networks. Both, the previous Anreizregulierungsverordnung, and the recent shift to empower the Bundesnetzagentur, sit already at federal level and states are not involved. Instead, the shift shows the impact of supra-national, EU-level regulation on shaping EU members states patterns of network regulation. This illustrates how EU-level legal requirements for regulatory independence can reshape the domestic allocation of authority within a member state. Great Britain and the Netherlands, as unitary states with a single national regulator (Ofgem and the ACM respectively), do not face an equivalent federalism question.

3.4 Regulatory complexity and overlapping processes

A recurring theme across jurisdictions is that investment regulation is procedurally complex, and that this complexity often arises from the interaction of instruments that are individually well-motivated but only loosely coordinated. In Australia, physical network planning (NER Chapter 5)

and economic revenue regulation (NER Chapter 6) are, in practice, tightly interdependent – the annual planning process feeds into the five-year economic forecast, which in turn constrains individual project decisions – yet the two chapters of the NER rarely cross-reference one another explicitly, despite requiring substantial repeated information flow between them, a source of process inefficiency identified directly by Csereklyei and Kallies (2026).

In Great Britain, successive reviews have found that the regulatory framework itself became a source of complexity: Ofgem’s 2008 ‘stepping back’ review was motivated partly by concern that RPI-X regulation⁴ was overly complex and might not deliver the investment required for a low-carbon energy sector, and the resulting RIIO (Revenue = Incentives + Innovation + Outputs) framework, while presented as a simplifying set of principles, produced outcomes in its first period that diverged from what was intended because of the gap between high-level principles and their detailed application at each price control review (Jenkins, 2025).

Germany’s recent reform is itself a direct response to legal and procedural complexity: replacing a multi-instrument ordinance regime (ARegV, StromNEV, GasNEV) with a smaller number of binding regulatory determinations issued by a single decision-making body is explicitly intended to streamline what had become a fragmented legal architecture, while simultaneously shortening regulatory periods from five to three years to allow faster correction of emerging cost pressures (Bundesnetzagentur, 2025). In the Netherlands, the ACM’s first attempt at firm-specific benchmarking (2000–2003) failed in part because of ambiguities in the underlying Electricity Act that were only exposed through litigation, prompting a shift to a simpler yardstick competition model based on aggregate sector costs from the second regulatory period onward (Nillesen and Pollitt, 2026) – an example of regulatory design being simplified specifically in response to legal complexity and resulting litigation risk. However, this has now shifted again to a focus on a revenue cap regulation based on actual costs, which is considered necessary to ensure sufficient network investment is forthcoming to address grid congestions (ACM, 2025).

3.5 Ownership, operation and governance models (DSO/DNSP, network ownership)

Ownership arrangements for distribution networks range from fully private to fully public, often within a single jurisdiction. In Great Britain, all 14 DNOs have been privately owned since the 1990 privatisation of the former Central Electricity Generating Board’s regional distribution assets (Jenkins, 2025). In the Netherlands, public ownership of distribution system operators is a binding statutory requirement, not merely the current factual pattern: the Energiewet’s privatisation prohibition (privatiseringsverbod) requires that shares in a distribution system operator be held, directly or indirectly, by one or more public bodies, and that unencumbered ownership of the distribution system itself rest with the distribution system operator, with an equivalent requirement placing transmission system operator shares directly or indirectly with the Dutch State (Energiewet, art.3.14). Germany sits between these positions: alongside roughly 20 larger, often privately or mixed-ownership distribution companies, the majority of Germany’s more than

⁴ Retail Price Index – X, with X standing for some form of efficiency factor.

800 DSOs are small, frequently municipally owned local utilities (Stadtwerke) (Brandstätt and Glachant, 2025).

Australia illustrates how ownership can vary within a single national regulatory framework applied uniformly regardless of ownership form: the Victorian and South Australian distribution businesses were fully privatised in the 1990s and 2000, two of the three New South Wales distribution businesses have since been 51 per cent privatised, while Essential Energy (NSW) and the Queensland distribution networks remain in government ownership (Kuiper, 2024). The National Electricity Rules apply the same building-block incentive regulation framework to these networks irrespective of ownership (Csereklyei and Kallies, 2026), providing a useful natural comparison for assessing whether ownership form affects investment behaviour independently of the regulatory regime applied to it. The United States displays the widest ownership diversity of all: investor-owned utilities (serving roughly three-quarters of retail customers and subject to cost-of-service or performance-based regulation by state commissions), municipal utilities owned and regulated by local government, member-owned cooperative utilities, and federal or state government generation-and-transmission entities all coexist, with materially different governance and regulatory treatment (Joskow and Schmalensee, 2025).

Beyond ownership of the network asset itself, jurisdictions are also increasingly distinguishing the network operator's traditional role (conveying electricity, DNSP in Australia, DNO in Great Britain) from an evolving distribution system operator (DSO) role involving active management of distributed energy resources (DER) and local flexibility markets – a transition that is further along in some jurisdictions than others, and which raises separate governance questions, including whether the network operator itself should be permitted to provide competing, contestable services (Jenkins, 2025; Csereklyei and Kallies, 2026). This distinction, and its implications for third-party access and ring-fencing, is taken up further in Section 9.

A CSIRO-commissioned comparative study of DSO governance models (Energy Catalyst, 2025) provides the clearest available cross-country picture of how this transition has actually been governed in practice, rather than only debated in principle. Great Britain, which the report describes as having moved beyond considering DSO models to now lead the world in deploying and operating them, requires at least a formally ring-fenced separation of a DSO from its DNO counterpart, underpinned by a formal Operational Agreement and an Independent Supervisory Board, but stops short of mandating full legal unbundling; individual companies have nonetheless gone further than this minimum where they judged it commercially sensible, with Scottish and Southern Energy Networks (SSEN) adopting full legal unbundling while UK Power Networks (UKPN) has instead pursued more comprehensive internal structural separation without full unbundling (Energy Catalyst, 2025). This graduated, minimum-floor-plus-company-discretion model contrasts with the European Union's approach, under which EU law mandates unbundling of DSO activities from supply activities, requires market-based procurement of flexibility, and bars DSOs from owning generation or storage assets except under strict conditions (Energy Catalyst, 2025) – a materially more prescriptive baseline than Great Britain's own domestic approach, notwithstanding Great Britain's history of EU membership and continuing regulatory proximity to EU practice.

The United States again shows the pattern of jurisdictional heterogeneity already noted for ownership (above) and federalism (Section 3.3): Energy Catalyst (2025) reports that in many states, DNSP functions remain embedded within vertically integrated utilities with no separate DSO function at all, while California and New York specifically assign DSO-like functions to existing utilities through state-level planning mandates and regulatory oversight, including requirements to competitively procure DER solutions and restrictions on utilities directly owning them – consistent with the ownership-restriction findings from Burger et al. (2019) and Lowder and Xu (2020) discussed in Section 9.2, and confirming that this is a settled feature of the US regulatory landscape in the states where it has been addressed at all, rather than an isolated finding from a single source. Taken together, this comparison suggests the DNO-to-DSO governance question is being answered along a spectrum running from EU-mandated structural unbundling, through Great Britain’s ring-fencing-with-discretion model, to a US pattern that is itself bifurcated between states that have addressed the question through explicit planning mandates (California, New York) and the many that, on this evidence, have not yet done so at all.

4. Regulatory Model

4.1 Cost-of-service / rate-of-return regulation

Cost-of-service regulation (COSR), sometimes called rate-of-return (ROR) regulation, remains the foundational regulatory model in the United States and, in modified form, underlies the building-block approach used elsewhere. Under COSR, a state public utility commission periodically conducts a formal “rate case” in which it establishes the utility’s allowed aggregate revenue requirement for a defined “test year”: operating expenses, depreciation, taxes, and a return on the utility’s regulated asset base (broadly, its net investment in used-and-useful plant) calculated at a commission-approved weighted average cost of capital are summed to produce the revenue requirement, which is then translated into a tariff structure across customer classes (Joskow and Schmalensee, 2025). Once set, rates remain fixed until the next rate case is initiated (Joskow and Schmalensee, 2025), creating “regulatory lag”.

Joskow and Schmalensee’s original 1986 account of this system, written near the start of the incentive-regulation reform movement they went on to help shape, is worth returning to directly because it makes explicit several features of COSR that later summaries tend to compress. They characterise the regulatory relationship as a long-term “regulatory contract” between customers (represented by the commission) and the utility: in exchange for an exclusive geographic franchise, the utility undertakes to supply reliable service at minimum cost, and the commission undertakes to compensate the utility for all costs “prudently” (in their reading, efficiently) incurred in meeting that obligation – a compensation commitment they identify as necessary in the first place, since without it a rational utility would not agree to supply service at all (Joskow and Schmalensee, 1986).

This “prudence” standard, they note, has both a short-run dimension (operating existing plant efficiently) and a long-run dimension (making efficient capital investment decisions in the first place), with a long-run investment decision judged prudent if it was optimal given what was known at the time it was made, regardless of whether it later turns out, with hindsight, to have been the right call – the doctrinal ancestor of the prudent-investment standard discussed further in Section 7.3, traceable to the US Supreme Court’s 1944 ruling in *Federal Power Commission v. Hope Natural Gas Co.* (1944) 320 U.S. 591, which gave regulators wide latitude over method, provided the result let the utility raise capital in the market (Joskow and Schmalensee, 1986).

They also identify a persistent technical problem underlying rate base regulation that is easy to lose in a purely descriptive summary: straight-line accounting depreciation and the true economic depreciation of a long-lived asset generally diverge, so the capital cost embedded in a COSR-derived price at any given moment does not, except by coincidence, equal the asset’s true economic cost of capital at that moment – a mismatch inflation makes worse, since accounting costs are based on historic rather than replacement cost (Joskow and Schmalensee, 1986).

Australia’s building-block model, while classified in the literature as a form of incentive regulation (Section 4.2), is structurally a direct descendant of rate-of-return regulation: the AER’s revenue

determinations are built up from the same underlying components – operating expenditure, return on and of capital (depreciation) applied to a regulatory asset base, and tax – as a US COSR revenue requirement, with the key difference that the building blocks are set prospectively for a multi-year regulatory period rather than being reset after each individual rate case (Kuiper, 2024, Csereklyei and Kallies 2026). This illustrates a broader point developed further in Section 4.3: the boundary between cost-of-service and incentive regulation is a matter of degree – how forward-looking, how indexed, and how firm-specific the revenue-setting mechanism is – rather than a clean binary.

4.2 Incentive regulation

Outside the United States, network revenue regulation today is near-universally structured as some form of incentive regulation, in which allowed revenues or prices are set prospectively for a multi-year regulatory period according to a pre-announced formula, partly decoupling the firm's profitability within the period from its actual costs and thereby creating a stronger incentive to outperform the regulatory allowance than exists under COSR (Joskow and Schmalensee, 2025; Nillesen and Pollitt 2026).

The canonical form is RPI-X (or CPI-X) regulation, introduced in Great Britain at privatisation in 1990s, under which allowed prices are permitted to rise with inflation less an efficiency (productivity) factor, X, fixed for the length of the control period (Jenkins, 2025; Nillesen and Pollitt, 2026).

A comparative overview of European distribution revenue models compiled by Kuiper (2024) confirms that France, Germany, the Netherlands, Norway, Sweden and Great Britain all now operate a form of incentive regulation, though the specific formula differs: Germany, France, Norway, Sweden and Great Britain apply a revenue cap, while the Netherlands applies a price cap; regulatory periods range from three to five⁵ years across these six countries; and Germany, the Netherlands, Norway, Sweden and Great Britain all incorporate formal efficiency benchmarking (yardstick-style), while France does not (Kuiper, 2024).

The Netherlands has applied incentive regulation based on yardstick competition since 2000, after an initial attempt at firm-specific benchmarking on a sample of 19 companies using DEA proved deeply contentious: the regulator (then DTe, since changed to ACM) capped the three-year X-factor at 8 per cent per year but required companies who were not capped to eliminate all measured inefficiency within the same three years, and the resulting disputes were significant enough to generate roughly 300 separate court cases before the Dutch competition authority (NMa) overturned and required revision of DTe's decisions in 2002 (Pollitt, 2026). The ACM has more recently signalled an intention to shift toward a more forward-looking, input-based

⁵ Kuiper (2024) reports 8 years for the UK. This number has been since changed and reversed back to 5 years as of RIIO-ED

2 regulatory period (running from 2023-2028).

framework from 2027, moving closer to the practices used in Great Britain (Nillesen and Pollitt, 2026, ACM, 2026).

Australia's building-block model is likewise classified as incentive regulation – specifically, RPI-X (referred to in Australia as CPI-X) applied through a revenue cap (Kuiper, 2024). As in Great Britain and the Netherlands, an efficiency (X) factor is intended to capture expected productivity improvement over and above a bare cost pass-through, and proponents of the model argued at its inception that a fixed, forward-looking regulatory period, combined with the threat of political pressure to keep prices low, would if anything create a risk of under- rather than over-investment (Kuiper, 2024). To be explicit about how this sits alongside Section 4.1: this review treats Australia's building-block model as a single hybrid design occupying one consistent position, combining a rate-of-return cost architecture (Regulated Asset Base, depreciation, return on capital) with an incentive-regulation revenue-cap classification, rather than as two competing descriptions; Sections 4.1 and 5.2 describe the same hybrid from its cost-architecture and revenue-formula angles respectively, and Section 4.3 discusses the hybridity itself as a comparative variable.

4.3 Hybridisation of traditional regulatory models

A recurring finding across this literature is that the textbook dichotomy between cost-of-service and incentive regulation describes the poles of a spectrum rather than the menu of choices actually available to regulators, and that most systems in practice combine elements of both. This is most explicit in the United States, where Joskow (2024) argues that performance-based regulation (PBR) – the preferred US terminology for incentive regulation, deliberately chosen by regulators over “incentive regulation” because the latter “sounds like a potential giveaway to utilities” should be understood as a set of “building blocks” – performance incentive mechanisms, revenue decoupling, multi-year rate plans, and incentives for new initiatives and pilot programs – that can be adopted individually or in combination, and that Joskow argues are properly viewed as complements to cost-of-service regulation (COSR) rather than substitutes for it (Joskow, 2024).

Multi-year rate plans (MYRPs), are one of the four PBR building blocks for introducing incentive properties in the US. Notably, Joskow (2024) distinguishes two “polar types” of MYRP that are easy to conflate: genuine incentive-based plans that index revenues to external productivity or input-cost measures, and “formula rate” plans that automatically true-up allowed revenue to the utility's actual realised costs.

A parallel hybridity is evident in Australia's building-block model, which pairs a rate-of-return revenue calculation with an incentive overlay (the efficiency benchmark and associated CPI-X-style adjustment), such that it sits, consistent with the international comparison (Kuiper, 2024).

Germany's transition from the ARegV ordinance regime to case-by-case Große Beschlusskammer of the Bundesnetzagentur determinations under RAMEN Strom is a further, if different, form of hybridisation: revenue caps and efficiency benchmarking (the hallmarks of incentive regulation) are retained, but the addition of within-period capital cost mark-ups for new investment reintroduces an element of more direct, near-contemporaneous cost recovery that is closer in

spirit to COSR's treatment of investment than to a pure *ex ante* incentive formula (Bundesnetzagentur, 2025).

These cases matter for how this review applies its own hierarchical framework (Section 2.4). Rather than forcing the US, Australia or Germany into a single node of the Regulatory Model – Design of Incentive Regulation hierarchy, we treat the degree of hybridisation itself as a comparative variable: the US combines COSR and PBR most explicitly and most heterogeneously (varying state by state); Australia and, in a different way, Germany combine a nominally incentive-based revenue formula with mechanisms that reintroduce more direct, current-cost recovery for investment specifically, which is a recurring theme we return to in Sections 6 and 8 when discussing capital expenditure treatment and risk allocation.

5. Design of Incentive Regulation

5.1 Price cap regulation

Under price cap regulation, the regulator fixes the maximum price (or average price across a basket of services) the firm may charge, typically indexed to inflation less an efficiency factor – the RPI-X formula introduced by Littlechild (1983) and applied at British privatisation (Nillesen and Pollitt, 2026; Jenkins, 2025). Because prices, rather than total revenue, are regulated, the firm bears volume risk: if demand turns out higher or lower than forecast, its realised revenue moves with it, for better or worse, until prices are next reset. Among the jurisdictions in this review, the Netherlands is the clearest example of price cap (control) regulation in its pure form, applied by the regulator since 2000 (Kuiper, 2024; Nillesen and Pollitt, 2026).

Great Britain’s own shift away from pure price cap regulation is instructive for understanding what RIIO changed, and what it kept. McHarg (2011) explains that the new system retained several core features of RPI-X: it remained an *ex ante*, incentive-based, inflation-linked price control built on the same underlying building blocks (the expected efficient cost of delivery plus an allowed return on capital), and Ofgem calculated the return on capital using the same principles as before, specifically to reassure capital markets that the change would not increase regulatory risk.

What changed was, in McHarg’s (2011) account, five things in combination: first, an output-led approach, under which the starting point for calculating required revenue became a set of agreed outputs across six categories (customer satisfaction, reliability and availability, safety, connection terms, environmental impact and social obligations), rather than beginning from cost alone⁶; second, a symmetric profit-sharing risk-sharing scheme, under which cost overruns as well as underspends are shared with consumers; third, “smart planning”, a decentralised, bottom-up planning process built on company business plans and enhanced stakeholder engagement rather than top-down direction; fourth, proportionate regulation, under which the intensity of regulatory scrutiny varies with the quality of a company’s business plan and its track record, rewarding better performers with lighter-touch review; and fifth, a strengthened emphasis on innovation, including a common efficiency rate applied to all network costs specifically to remove the CAPEX/OPEX distortion discussed in Section 6.4, and an expanded innovation stimulus fund open to non-network as well as network bidders. RIIO also increased the standard price control period from five to eight years at its introduction, a change later reversed for the reasons discussed in Section 5.5 (McHarg, 2011).

⁶ “Having agreed primary outputs and secondary deliverables, these will then be used to calculate the company’s ‘base revenue’ for the price control period (the expected efficient costs of delivery plus the cost of capital). Total allowed revenue from consumers will consist of base revenue, adjusted in the light of performance indicators, and also adjusted for uncertainty mechanisms. The former will include rewards and penalties for performance against outputs (although a range of performance incentives may be used, including purely reputational incentives, depending upon the output in question) as well as upfront efficiency incentives. The latter will include inflation indexation plus a variety of revenue drivers and reopeners” (McHarg, 2011, p 326).

5.2 Revenue cap regulation

Under revenue cap regulation, by contrast, the regulator fixes the firm's total allowed revenue for the period (or a formula for it), and the price per unit is then derived residually from that revenue target and forecast volumes, with most schemes including a true-up mechanism that corrects for any gap between forecast and actual volumes in a subsequent period. This shifts volume risk substantially away from the firm and toward consumers or toward the regulatory settlement process itself. Revenue cap regulation is the dominant model in this review's comparator set: Kuiper's (2024) comparative table classifies France, Germany, Norway, Sweden, Great Britain and Australia (via its building-block model) as revenue cap jurisdictions, leaving the Netherlands as the only price cap jurisdiction among the group. The prevalence of revenue caps reflects a widely shared regulatory judgment that, for a natural monopoly network business with largely fixed costs, volume risk is more efficiently borne by the party facing the systematic driver of that risk – electrification and decarbonisation policy, in the current period – rather than by the network operator, whose costs do not fall proportionately with lower-than-forecast throughput.

It is worth pairing this mechanical description with evidence on whether incentive-based revenue and price control in practice delivered the outcomes it was designed to.

Domah and Pollitt (2001) cited in Jamasb and Pollitt's (2007) empirical review of nearly two decades of British distribution regulation since notes finds substantial, measurable gains: unit costs of the post-privatisation successor distribution businesses fell by roughly 20 per cent between 1994 and 1998, and labour productivity nearly doubled between 1990–91 and 1997–98. Jamasb and Pollitt report that continued efficiency gains and successively tighter price control reviews left UK network access charges among the lowest in the European Union by the mid-2000s, with corresponding benefits for the affordability of electricity bills for low-income consumers specifically.

These gains were not evenly distributed, however: Jamasb and Pollitt (2007), citing Yarrow (1992) and Domah and Pollitt (2001) note that most of the benefit accrued to certain customer classes rather than uniformly across all consumers, that domestic prices initially rose relative to industrial prices by more than expected in the early years of reform. This is a rare instance in the literature reviewed here of a jurisdiction's incentive regulation being assessed on delivered outcomes over an extended period, rather than only on its design, and provides useful grounding for the outcome-effectiveness question the Comparative Synthesis is intended to address directly.

5.3 Hybrid and menu regulation

Menu regulation is the most developed hybrid mechanism in this literature, designed specifically to address the problem that a regulator, lacking the firm's own private information about its efficient cost, cannot set a single allowance-and-incentive-rate combination that is simultaneously generous enough to be accepted and tight enough to avoid overcompensating an efficient firm.

Ofgem's Information Quality Incentive (IQI), first applied in the fourth electricity distribution price control (DPCR4) and carried through into RII0-ED1, offered regulated firms a menu of expenditure

allowance/incentive-rate combinations – a higher allowance paired with a lower sharing rate, or a lower allowance paired with a higher sharing rate – constructed so that a firm’s own best interest is served by choosing the combination that reflects its true, privately known expenditure forecast, thereby incentivising truthful revelation rather than the padding of cost forecasts (Jamasb, 2021).

Ofgem’s own subsequent consultations suggest this menu-based approach did not persist indefinitely: by the RII0-2 framework consultation in 2018, Ofgem was openly questioning whether the IQI had worked as intended, since companies had generally underspent relative to their own forecasts, suggesting the menu was not reliably eliciting truthful revelation (Ofgem 2018). In Ofgem’s most recent RII0-ED3 Framework Decision (Ofgem, 2025), the IQI has been replaced by a Business Plan Incentive.

Menu regulation has also been influential outside Great Britain as a design template, even where not adopted in full. Ofwat, the water regulator, operated a related but distinct CAPEX incentive scheme in which a company’s menu position was determined by the regulator from the ratio of the company’s proposed to assessed CAPEX, rather than being freely chosen by the company (Frontier Economics, 2017) – illustrating that “menu regulation” covers a family of mechanisms rather than a single design. In Australia, industry submissions to the AER’s 2023 review of incentive schemes explicitly proposed menu regulation, modelled on the IQI, as a tool to improve the accuracy of CAPEX forecasts, and technical advice prepared for Australian regulatory consideration set out how a menu approach could in principle be extended to TOTEX allowances and incentive sharing rates under the National Electricity Rules (Boardroom, 2023; Frontier Economics, 2017) – though, as of the material reviewed here, menu regulation has not been formally adopted in the Australian building-block framework.

5.4 Benchmarking and yardstick competition

Where a jurisdiction regulates a sufficiently large number of comparable firms, efficiency benchmarking allows the regulator to infer efficient cost levels from the observed cost performance of the sector as a whole, rather than relying solely on firm-specific cost assessment. The practice is global in scale: Kufeoglu et al. (2018), cited in Pollitt (2026), estimate there are more than 7,600 electricity distribution utilities across 175 countries, typically accounting for 15–25 per cent of total electricity system costs, and Great Britain’s 1993 introduction of distribution benchmarking under Stephen Littlechild is widely credited as the model that subsequently inspired benchmarking programmes in many other jurisdictions (Pollitt, 2026).

Kuiper’s (2024) comparative analysis finds that Germany, the Netherlands, Norway, Sweden and Great Britain all incorporate formal yardstick-style efficiency benchmarking, while France does not. The most important statistical techniques in the applied literature include: non-parametric Data Envelopment Analysis (DEA), which estimates an efficient cost frontier directly from observed firms without assuming a functional form, and Stochastic Frontier Analysis (SFA), which estimates a cost function econometrically and separates inefficiency from random noise; Corrected Ordinary Least Squares (COLS) represents a third, deterministic parametric frontier approach. COLS has historically played an important role in Great Britain’s electricity distribution regulation,

although modern regulatory frameworks increasingly combine multiple benchmarking approaches rather than relying on a single frontier technique (Pollitt, 2026).

Norway's regulator (NVE) has applied DEA-based benchmarking to its approximately 123 distribution firms since 1997, with annual updates being introduced after 2007 (Bjørndal et al., 2018). Bjørndal et al., 2018, using a “dataset of 123 Norwegian electricity distribution firms illustrated that managerial inefficiency can be estimated in a meaningful way by comparing among firms operating in comparable environments, i.e., a homogeneous technology. The proposed model is used to compare the effect of conditioning on total efficient costs and revenues, firms' rate of return, and customers' prices.” Based on the results, they “observe that the use of conditional benchmarking methods may lead not only to a different peer selection and changes in aggregate efficient cost, but also to a reallocation effect that affects the relative profitability of firms and relative customer prices. Thus, conditional benchmarking methods may provide a fairer basis for setting revenue caps” Bjørndal et al., 2018, p 719).

Sweden's regulator applies the same underlying approach as Norway's, using DEA to set efficiency requirements; separately (Pandur and Jonsson (2015) cited in Lundgren and Vesterberg (2024). Lundgren and Vesterberg (2024) apply a four-component SFA model to Swedish distribution firms as an independent academic exercise, separating persistent from transient inefficiency, and find that neither growing small-scale generation nor electric vehicle uptake has yet had a material effect on measured technical inefficiency, a finding relevant to the debate in Section 9 on whether distributed energy resources are straining network cost efficiency.”

Pollitt's (2026) direct comparison of Great Britain, the Netherlands and Germany shows three genuinely distinct implementation philosophies rather than three variations on a single method. Great Britain applies benchmarking to a small number of firms (14 DNOs), backed by heavy investment in data cleaning and an extensive engagement process that has built a comparatively high degree of company trust in the results; for the current price control (2023–2028) Ofgem combined four separate models – three based on a composite scale variable (COLS) and one on disaggregated activity benchmarking – blending five years of actual data with six years of simulated data incorporating projected electric vehicle and heat pump uptake, and set X factors on the assumption that each firm would reach the 85th percentile of measured efficiency by the third year of the period (Pollitt, 2026); the next price control (ED3) will run from 1 April 2028 to 31 March 2033 and, notably, embeds this five-year cycle within a much longer 25-year strategic network-planning horizon for the first time (Ofgem, 2025).

Germany, by contrast, applies the most data-intensive approach of the three: the Bundesnetzagentur's first benchmarking exercise in 2007 analysed 328 electricity and 488 gas distribution companies using DEA, SFA and COLS together (Pollitt, 2026).

The average German efficiency scores rose from 92.2 per cent in 2008 to 95.9 per cent in 2024, evidence of convergence Pollitt (2026) reads as reducing the marginal importance of firm-specific benchmarking results to revenue outcomes over time.

The Netherlands took a third path again: an initial 2000 DEA exercise on 19 companies, with an 8 per cent per year X-factor cap but a requirement that firms who were not capped eliminate all measured inefficiency within just three years, proved so contentious that it generated roughly 300 separate court cases and was ultimately overturned by the Dutch competition authority (NMa) in 2002 (Pollitt, 2026; see also Section 4.2), after which the Dutch regulator abandoned firm-specific frontier benchmarking altogether in favour of the industry-wide yardstick approach described in Section 4.2.

One further finding from this comparison is worth flagging as a genuine, if somewhat surprising, gap in current practice rather than a limitation specific to any one jurisdiction: despite a global population of more than 7,600 distribution utilities, almost no regulator makes use of international comparator data when benchmarking its own firms. Pollitt (2026), citing Agrell and Bogetoft (2018) and CEER (2026), notes that among European countries using frontier efficiency techniques, Iceland has been found to use an international sample, and in CEER's most recent survey of 24 European regulators, only Portugal reported doing so. A partial exception is the Netherlands, where the single national electricity and gas transmission system operators are benchmarked against other European TSOs (CEER, 2026).

This means that jurisdictions with genuinely small domestic comparator pools – Great Britain's 14 DNOs, or Australia's 13 DNSPs –, in current practice, may not or not comprehensively be compensating for that limitation by drawing on the far larger international population that in principle exists⁷. This is a design choice this review has not seen explicitly justified in any of the sources reviewed and that seems a natural candidate for further investigation.

This is a direct illustration of the depth-of-regulation point raised in Section 3.2: benchmarking is statistically more powerful with more comparable firms (as in Germany's 800-plus DSOs or Norway's 123 distribution companies) than with a small population (as in Great Britain's 14, or Australia's 13 DNSPs), which may help explain why Great Britain and Australia rely more heavily on firm-specific cost assessment layered on top of benchmarking than do Germany, Norway or the Netherlands.

5.5 Regulatory period length

Regulatory period length trades off two competing considerations: longer periods give the firm stronger and more durable incentives to outperform its allowance (because the firm keeps any efficiency gains for longer before the next reset claws them back into the baseline), but also increase the risk that the allowance becomes stale as costs, technology or policy shift within the period. Kuiper's (2024) comparative table finds a range from three to eight years across the six European countries examined: three to five years for the Netherlands and Norway, four years for France and Sweden, five years for Germany, and eight years for Great Britain's RIIO-ED1 (2015–2023). Great Britain's own history shows this parameter itself being actively adjusted in response

⁷ We note that the Australian Energy Regulator's annually published benchmarking report does contain international benchmarking for OPEX but not CAPEX. (AER, 2025).

to experience: five-year periods under RPI-X and the first RIIO framework gave way to an eight-year period for RIIO-ED1, which was in turn judged to have allowed companies to earn excess returns with limited effort due to output targets being set too low and revenue allowances too high (CEPA, 2018; Citizens Advice, 2023, cited in Jenkins, 2025), prompting a return to a five-year periods for RIIO-ED2 (2023–2028) and, RIIO-ED3 (1 April 2028 to 31 March 2033) (Ofgem, 2025).

Notably, Ofgem’s ED3 decision explicitly considered and rejected moving away from the five-year duration, reporting that a slim majority of consultation respondents favoured retaining it as a good balance between investor certainty and the ability to periodically reassess incentives (Ofgem, 2025); rather than shortening the price control cycle itself, Ofgem’s response to the case for longer-term visibility has instead been to embed the five-year cycle within a 25-year strategic network-planning horizon running alongside it (Ofgem, 2025). Germany has moved in a different direction for related reasons: the Bundesnetzagentur’s RAMEN Strom decision confirms the fifth incentive-regulation period will begin 1 January 2029, with periods shortened from five to three years specifically to allow faster correction of emerging cost pressures (Bundesnetzagentur, 2025). Read together, Britain and Germany turn out to be responding to the same underlying pressure – the difficulty of setting a durable allowance amid rapid, uncertain change – with two different instruments: Germany has shortened the price control cycle itself, while Britain has kept the cycle length fixed and instead lengthened the strategic planning horizon that sits around it. This suggests that “regulatory period length” and “planning horizon” are two analytically separate variables that this literature, and this review’s outline, have so far treated as a single one.

5.6 Sharing mechanisms

Sharing mechanisms determine how any gap between a firm’s allowed and actual costs (or revenue) within a period is divided between the firm and consumers, and are the specific design lever through which a regulator sets the overall strength of the incentive scheme. Menu regulation, discussed in Section 5.3, makes the sharing rate itself a variable the firm can influence through its own choice of allowance; the IQI matrix, for instance, pairs each allowance level with a corresponding sharing rate such that firms revealing more accurate (lower) forecasts are rewarded with a higher sharing rate on any further outperformance (Frontier Economics, 2017).

In the United States, several state multi-year rate plans include analogous earnings-sharing mechanisms that split returns above a specified benchmark between the utility and customers – for example, New York’s framework includes a one-way (excess) earnings-sharing mechanism (Lowry et al., 2017 cited in Joskow, 2024).

This review distinguishes within-period sharing mechanisms, covered here, from the inter-period efficiency carryover mechanisms that determine whether efficiency gains made in one regulatory period are clawed back into the following period’s baseline allowance or allowed to persist – a design choice with first-order consequences for CAPEX/OPEX neutrality that is treated in its own right in Section 6, given its direct connection to the CAPEX/OPEX bias problem introduced in Section 2.3.

6. Investment Incentive Mechanisms

6.1 CAPEX-based regulation

The traditional approach to network expenditure regulation assesses capital and operating expenditure separately: CAPEX is added to the regulatory asset base (RAB) and recovered gradually over time through depreciation plus a return on the undepreciated balance, while OPEX is assessed as a pass-through or benchmarked allowance recovered within the period it is incurred (Csereklyei and Kallies, 2026). Australia’s National Electricity Rules follow this separated approach: capital expenditure is defined as an addition to the RAB that is amortised over time and carries a pre-determined rate of return, assessed and approved through a distinct CAPEX forecasting and testing process (NER 6.5.7) that runs alongside, but is procedurally separate from, OPEX assessment (NER 6.5.6). The United States follows essentially the same separated logic under COSR (Section 4.1): Lowder and Xu (2020), reviewing the evolution of the US distribution system for the National Renewable Energy Laboratory, confirm that authorised utility revenue in the US has traditionally comprised CAPEX (investments in physical rate-base assets) and OPEX (recurring costs such as labour, fuel and maintenance), and note the Averch-Johnson capital-bias dynamic, also discussed in Section 6.4 as a direct consequence of a rate-base structure that allows regulated cost recovery specifically on CAPEX, regardless of whether a less capital-intensive alternative might meet the same need more efficiently.

6.2 TOTEX approaches

An alternative design treats capital and operating expenditure as a single, undifferentiated “total expenditure” (TOTEX) pool, assessed and benchmarked together, with the split between what is expensed immediately and what is capitalised into the RAB determined mechanically after the TOTEX allowance is set, rather than assessed separately for each cost category.

Great Britain provides the most developed example: Ofgem introduced TOTEX benchmarking from DPCR5 and extended it further under RIIO, and the Frontier Economics report (2017) states that it is generally accepted among companies and commentators that Ofgem’s TOTEX reforms have been successful in eliminating any material incentive to capitalise operating expenditure, in both a physical and an accounting sense. The Netherlands offers an earlier and structurally distinct example: the Dutch regulator (originally DTe, now the ACM) has applied a total-cost framework since the inception of Dutch incentive regulation, but based the underlying cost measure on the accumulated stock of installed assets (a “capital consumption” concept) rather than on annual capital expenditure flows as in the Ofgem framework, requiring DTe to reconstruct historical asset values across the sector before the yardstick measures could be credibly applied (Frontier Economics, 2017).

The Frontier Economics report (2017), prepared to inform Australian regulatory consideration of TOTEX reform, notes that adopting a TOTEX approach would render several existing NER mechanisms redundant – including the AER’s efficiency benefit sharing scheme (EBSS) and CAPEX incentive guideline – and would require the AER to determine, after setting the total efficient

quantum of expenditure, what portion should be recovered within the current period versus capitalised into the RAB and recovered gradually, a design question with no equivalent under the current separated approach. As of the material reviewed in this project, Australia's building-block model retains the separated CAPEX/OPEX approach described in Section 6.1, making the TOTEX/non-TOTEX distinction itself a live point of difference between the Australian and British/Dutch regimes, rather than merely a historical stage every jurisdiction eventually passes through.

A more critical, EU-level assessment of TOTEX reform's actual effectiveness has since emerged and is worth setting directly against the favourable British assessment above. Pototschnig and Rossetto (2024), in a report prepared by the Florence School of Regulation for the European Union Agency for the Cooperation of Energy Regulators (ACER), argue that a properly implemented TOTEX approach requires the regulator to fix the CAPEX-OPEX ratio (the split between "fast money" and "slow money" described in Section 6.3) in advance and hold it constant regardless of the solution the network operator actually chooses; only under that condition is the CAPEX bias genuinely neutralised. They note two practical failure modes: first, even a properly designed TOTEX scheme is only bias-neutral within a single regulatory period, since regulators typically revisit the fixed CAPEX-OPEX structure at the next reset, reintroducing a version of the bias at the boundary between periods; and second, some schemes labelled "TOTEX" in practice do not actually hold the CAPEX-OPEX structure fixed even within a single period, which they characterise as failing to address the CAPEX bias at all despite the TOTEX label.

To make this concrete: a genuine TOTEX scheme, on Pototschnig and Rossetto's (2024) account, must commit in advance to a fixed capitalisation rate (the proportion of any pound or euro of allowed expenditure that is treated as CAPEX versus OPEX, described in Section 6.3) that does not change regardless of which specific solution the firm ends up choosing. Instead, the authors propose that a TOTEX approach should "consider the possibility for network companies to opt for non-traditional, more efficient and innovative solutions" (Pototschnig and Rossetto, 2024, 22).

The European Commission's November 2023 EU Action Plan for Grids reflects the same concern at policy level, finding that prevailing network tariff structures across the EU still focus disproportionately on CAPEX and under-compensate the rising operational costs of digitalisation, data processing and flexibility procurement, and directing national regulatory authorities to review their tariff methodologies accordingly (Pototschnig and Rossetto, 2024, European Commission, 2023, Art. 5). The Plan tasked ACER with the development of a guidance for more efficient investment into revenue setting. A subsequent 2026 report recommended that efficient investment could be unlocked by inter alia, avoiding CAPEX bias, allowing revenue collection based on ex ante determination and eliminating rigid expenditure caps by including the possibility of ex-ante or ex-post adjustments of caps (ACER, 2026).

Read alongside Section 6.4's account of Great Britain's own TOTEX reforms, this suggests the Frontier Economics (2017) assessment that Britain has successfully eliminated CAPEX bias should be read as an assessment of implementation quality specific to the British case, rather than evidence that TOTEX regulation as a category reliably solves the problem.

6.3 Capitalisation rules

Where CAPEX and OPEX are assessed together under a TOTEX framework, a capitalisation rule is still required to translate the combined allowance back into what is expensed immediately (“fast money”) versus capitalised into the RAB and recovered over the asset’s depreciation life (“slow money”). Ofgem’s approach, refined through the IQI mechanism described in Section 5.3, used a single, company-specific capitalisation rate and incentive rate (Frontier Economics, 2017).

The specific choice of capitalisation rate is not a neutral technical parameter: it directly determines how much of any given expenditure is loaded onto current customers versus future ones, and how quickly a company’s cash flow responds to spending decisions. More on financeability will be discussed in Section 8.

6.4 CAPEX/OPEX bias

The risk that separated CAPEX/OPEX regulation systematically biases firms toward capital-intensive solutions is a recurring concern across this literature, with roots in the Averch-Johnson (1962) prediction that rate-of-return regulation increases the capital intensity of production where the allowed return exceeds the true cost of capital (Csereklyei and Kallies, 2026; Kuiper, 2024). The bias is not purely theoretical: the Frontier Economics report (2017) records that, in the lead-up to TOTEX reform in Great Britain, the water regulator Ofwat’s own consultation concluded that a CAPEX bias existed in that sector, attributable partly to the regulatory methodology itself (differential incentive strength, or “aiming up”, on the allowed cost of capital, p57) and partly to company culture favouring CAPEX-heavy solutions.

Direct behavioural evidence is also available from the electricity sector: the same report notes that some companies changed how they classified expenditure as OPEX or CAPEX between price controls in ways that generated regulatory outperformance purely from a change in accounting treatment, rather than any genuine improvement in efficiency – a finding that illustrates why CAPEX/OPEX neutrality, rather than any particular CAPEX or OPEX allowance level, is the outcome most TOTEX reforms are actually designed to secure.

Brunekreeft and Rammerstorfer (2020) offer a formal theoretical account of a distinct, second channel generating the same bias, independent of the Averch-Johnson mechanism, they termed “OPEX-disadvantage”. In their model, where CAPEX and OPEX are substitutable ways of meeting the same system need, a regulated firm facing operating-cost risk can reduce its own risk, and thereby its true cost of capital, by rebalancing spending toward CAPEX and away from risk-bearing OPEX.⁸

⁸ “Under the regulation, the strategic incentive for the regulated firm is to reduce overall risk at the expense of higher costs. By using inefficiently much CAPEX (and inefficiently little OPEX), the firm reduces risk, while the allowed rate-of-return on capital stays at the same (externally determined) level. As a result, the allowed rate-of-return on capital is higher than the true cost of capital, creating a margin for excess profits. This risk-rebalancing comes at the expense of

Because this bias arises from risk-shifting rather than from an excessive allowed return, it can persist under regulatory designs that successfully address the classical Averch-Johnson channel.

As a remedy, Brunekreeft and Rammerstorfer, and related work by von Bebenburg, Brunekreeft and Burger (2023) cited in Pototschnig and Rossetto (2024), propose a “fixed-OPEX-CAPEX-share” (FOCS) mechanism: a variation on TOTEX regulation under which the regulator pre-commits to a fixed ratio between allowed OPEX and CAPEX revenue, holding that ratio constant regardless of the mix of solutions the firm actually adopts, on the reasoning that FOCS is both theoretically effective against OPEX-risk-driven CAPEX bias and comparatively straightforward to implement relative to more complex output-based alternatives. This connects directly to the critique in Section 6.2: Pototschnig and Rossetto’s (2024) finding that many real-world TOTEX schemes fail to hold the CAPEX-OPEX structure genuinely fixed, even within a single period, means that FOCS’s theoretical effectiveness depends heavily on an implementation discipline that this review’s evidence suggests is not reliably present in practice.

6.5 Efficiency carryover mechanisms

Efficiency carryover mechanisms determine whether cost savings a firm achieves partway through a regulatory period are retained by the firm only until the end of that period (after which a lower baseline is locked in for the next period) or are allowed to persist, undiminished, for a further fixed number of years regardless of when in the period they were achieved – a design choice intended to lessen incentives for a firm to time its efficiency efforts strategically around the regulatory cycle.

Victoria’s former state regulator, the Office of the Regulator-General (ORG), introduced such a mechanism for its 2001–05 price control, and, unusually among the schemes surveyed here, applied it to combined OPEX and CAPEX savings rather than to OPEX alone (Frontier Economics, 2017).

When the Essential Services Commission (ESC) succeeded the ORG and reviewed the mechanism for the 2006–10 period, it concluded that CAPEX savings differ fundamentally from OPEX savings in this context: because CAPEX can be deferred rather than genuinely saved, rewarding CAPEX carryover risked compensating firms for savings that were not sustained or were not genuine efficiencies at all, whereas OPEX’s more incremental, harder-to-defer nature made its carryover a more reliable signal of true efficiency gain. The ESC accordingly restricted the carryover mechanism to OPEX only from 2006–10 (Frontier Economics, 2017) – a decision that pre-figures the AER’s current Efficiency Benefit Sharing Scheme (EBSS), which likewise applies only to OPEX, with CAPEX-specific incentives handled separately through the AER’s CAPEX incentive guideline and, since NER 6.5.8A, the Capital Expenditure Sharing Scheme (CESS) (Csereklyei and Kallies, 2026).

higher costs (due to inefficient production), but these are passed through in the regulated revenue. This establishes the CAPEX-bias.” (Brunekreeft and Rammerstorfer 2020, p 32).

The ESC itself acknowledged the resulting asymmetry could create a new distortion – an increased incentive to capitalise operating costs in order to secure carryover rewards unavailable on the CAPEX side – illustrating that even a carryover mechanism designed specifically to correct one incentive problem can reintroduce a version of the CAPEX/OPEX bias problem from Section 6.4 through a different channel.

6.6 Output- and outcome-based incentives

Beyond controlling the level of expenditure, most incentive regulation regimes also attach financial rewards or penalties to measurable service outputs, on the premise that expenditure control alone cannot guarantee that money is well spent. Great Britain's RIIO framework (Revenue = Incentives + Innovation + Outputs) makes this explicit in its name: it pairs the revenue-cap-plus-benchmarking core described in Sections 4–5 with Performance Incentive Mechanisms (PIMs) covering six outcome areas – customer satisfaction, reliability and availability, safety, connection terms, environmental impact and social obligations (McHarg, 2011). Australia's National Electricity Law imposes direct statutory service obligations on networks – safety, reliability and service standards under section 2D NEL.

Brunekreeft's (2023) study for the Dutch regulator ACM identifies a broader shift he identifies across several jurisdictions' regulatory theory and practice: a move away from pure efficiency-oriented regulation, which works well at incentivising cost control but is not well suited to driving the network expansion and reinforcement the energy transition requires, toward what he terms "efficient investment-oriented regulation" – retaining efficiency as a constraint. He explains output-oriented regulation (OOR), "which supplements the base regulation with revenue elements that reflect the achievement of specifically determined regulatory output targets or performances. Output-oriented regulation can incentivize activities that require cost increases and upfront expenditures and can capture external effects" (Brunekreeft, 2023, page 13). He frames the distinctive contribution of OOR specifically as its capacity to capture external effects: costs or benefits that fall on third parties rather than on the network operator making the decision, which base efficiency-oriented regulation, aimed at internal effects, is not designed to address. Notably, the ACER (2026) report on DSO revenue settings forecasts that the Netherlands have the highest relative increase in annual investment needs of all European countries, with 2027 investment projected at 2.5 times higher than in 2024 and over four times the 2021 level – revealing that previous regulatory models have not sufficiently addressed network congestion issues exacerbated by transition pressures (ACM, 2025) .

6.7 Innovation incentives

Innovation funding mechanisms vary from dedicated competitive funds to partial cost pass-through to regulatory sandboxes exempting innovative trials from standard rules. Great Britain has the most developed and longest-running set of mechanisms: a company-specific Network Innovation Allowance (NIA, in DPCR5, RIIO-ED1, RIIO-ED2, and RIIO-ED3), a use-it-or-lose-it fixed revenue amount for smaller projects; a competitive sector-wide fund, evolving from the Low Carbon Network Fund (LCNF) at DPCR5 to the Electricity Network Innovation Competition (NIC)

at RIIO-ED1 to the Strategic Innovation Fund (SIF) at RIIO-ED2 and RIIO-ED3; and an Innovation Roll-out Mechanism (IRM) worth 0.5–1 per cent of base revenues (Jenkins, 2025; Kuiper, 2024; Ofgem, 2025).

Evaluation of these funds has proven difficult: Jenkins (in Glachant, Joskow and Pollitt, 2025) reports substantial underspend against allowances in both DPCR5 (around £302 million spent, well below what had been allowed) and RIIO-ED1, and notes Ofgem’s own acknowledgement that no centralised record exists of how many projects DNOs have actually funded across the various schemes – raising the open question of whether innovation funding has been calibrated to genuine need or set too generously upfront relative to what companies have been willing or able to spend.

Other jurisdictions take materially different approaches to the same problem. Germany allows networks to recover up to 50 per cent of R&D project costs not already covered by public funding through a dedicated regulatory incentive mechanism, on top of large separate federal R&D funding programmes, and, like several other European countries, has piloted a regulatory sandbox permitting exemptions from standard network rules for approved trial projects (Kuiper, 2024; Brandstätter and Glachant, 2025).

France requires each distribution network to propose an annual R&D budget for regulatory approval (Kuiper, 2024). Regulatory sandboxes more broadly have been adopted across Europe – Meeus and Rosetto (in, 2025), drawing on Beckstedde et al.’s (2023) analysis of 72 approved European sandbox projects (concentrated in distributed energy resource integration, retail innovation, local energy sharing and self-consumption), find the instrument broadly effective at fostering innovation, but flag that the Netherlands, one of the earliest adopters of a sandbox programme, has since closed it, underscoring that design details – who administers the programme, what derogations may be granted, and how lessons learned are captured and disseminated – matter as much as the basic instrument choice.

7. Investment Governance

7.1 Ex ante versus ex post review

Investment governance regimes combine *ex ante* controls (assessing a project or forecast before expenditure occurs) with *ex post* review (assessing actual outcomes after the fact), and the literature is consistent that both are needed but that leaning too heavily on either creates its own problems. Pollitt, Duma and Covatariu (2025) frame this as a trade-off sharpened by the energy transition: as investment needs become larger and less certain, purely *ex ante* price controls must tolerate more over- or under-investment, or rely more heavily on reopeners to adapt mid-period – but frequent reopeners in turn undermine the credibility of the *ex ante* settlement, and the resulting exposure to *ex post* rulings can itself raise the cost of capital investors demand. A cross-country pattern captured in the AEC’s submission to the AER’s 2023 incentive scheme review is that Germany and the Netherlands both retain formally separate *ex ante* OPEX and CAPEX allowances, but apply their TOTEX efficiency incentives *ex post* across the combined expenditure – a hybrid design intended to address CAPEX/OPEX substitution risk (Section 6.4) while still giving firms an *ex ante* revenue framework to plan against (AEC submission, 2023, citing Frontier Economics, 2017). Australia’s building-block model combines an *ex ante* capital expenditure forecast acceptance process with two distinct *ex post* mechanisms – a reduction to the RAB roll-forward for inefficient past CAPEX under NER S6.2.2A, and the *ex ante*-incentive-with-ex-post-review structure of the Capital Expenditure Sharing Scheme (CESS) described in Section 6.5 – illustrating that “*ex ante*” and “*ex post*” review are not mutually exclusive design choices but are typically layered within a single regime (Csereklyei and Kallies, 2026).

Ofgem’s ED3 Framework Decision (2025) offers an example of a regulator openly weighing this trade-off rather than resolving it implicitly through mechanism design alone. Ofgem explored moving toward a more *ex post* model for ED3 (2028–2033) – in effect, funding a larger share of network investment through cost pass-through or after-the-fact assessment – but ultimately decided to retain a largely *ex ante* approach, funding the majority of network investment before the price control period begins and relying on uncertainty mechanisms, including a reduced and more targeted set of reopeners, to manage in-period risk (Ofgem, 2025). Ofgem’s own stated reasoning tracks the trade-off in this literature closely: *ex ante* allowances keep the cost of capital low and give companies a stronger incentive to outperform an efficiency assumption they know they will not be able to revise, but the effectiveness of this approach depends entirely on the regulator’s ability to identify efficient costs accurately in advance, given information asymmetry and given that cost drivers are themselves likely to change during the five-year period (Ofgem, 2025). Stakeholders were split: some favoured limited *ex post* regulation specifically to manage cost uncertainty from supply chain pressures and skilled labour shortages, but the majority view, which Ofgem adopted, was that *ex post* regulation should be confined to specific, clearly-evidenced circumstances rather than becoming a general feature of the framework, out of concern for the risks it would pose to both companies and consumers (Ofgem, 2025).

Germany's RAMEN Strom framework illustrates a third variant again: rather than choosing between *ex ante* and *ex post* treatment of investment as a whole, it applies a hybrid, notification-based procedure specifically to new capital expenditure incurred after a period's base year. Under the CAPEX markup (Kapitalkostenaufschlag) mechanism, a network operator is required only to notify (anzeigen), rather than formally apply for approval of, the mark-up it intends to apply to its revenue cap for the coming year, by 30 June of the preceding year; that notified figure is then reconciled *ex post* against actual incurred capital costs through the regulatory account (Regulierungskonto), with any difference carried forward and interest-adjusted (Bundesnetzagentur, 2025, items 11, 14). This seems to sit at neither pole: procedurally lighter than a full *ex ante* application-and-approval process (of the kind Germany does still use for research and development project funding specifically, discussed in Section 7.2), but not a pure *ex post* pass-through either, since the notified figure still operates as the binding basis for revenue within the year, subject only to a subsequent true-up rather than a subsequent approval decision.

7.2 Investment approval processes

Formal investment approval in Australia operates at two levels. At the revenue-determination level, the AER must accept a DNSP's forecast capital expenditure for the coming regulatory control period if satisfied that it reasonably reflects the capital expenditure criteria under NER 6.5.7(c): the efficient costs of achieving the capital expenditure objectives, the costs a prudent operator would require, and a realistic expectation of demand and other cost inputs. At the individual-project level, projects exceeding a materiality threshold are additionally subject to the Regulatory Investment Test for Distribution (RIT-D) described in Section 7.4. Merits review of AER determinations – formerly available, in limited form, through the Australian Competition Tribunal – was removed in 2017 with the introduction of section 44AIA into the Competition and Consumer Act 2010 (Cth),⁹ leaving judicial review as the only remaining avenue for a network to challenge a determination, and confining that avenue to whether the AER acted within its legal powers rather than whether its decision was substantively correct. This is a significant governance design choice in its own right: it removes a layer of substantive appeal that exists, in different forms, in some other jurisdictions' investment approval processes.

The Netherlands operates a structurally distinct approval process built around a standalone, periodically updated investment plan (investeringsplan) rather than being folded into the periodic revenue determination itself. Transmission and distribution system operators are required by the Energiewet (continuing the approach previously taken under the Electricity Act 1998) to prepare a periodic investment plan setting out expected market developments over a defined outlook period and the investments and measures the operator will take in response, drawing on national and regional planning inputs such as the Integrated National Energy and Climate Plan and regional energy strategies (Dutch Energy Law, explanatory memorandum). Draft investment plans are opened to public consultation – anyone, not only directly affected parties, may submit views –

⁹ Through the Competition and Consumer Amendment (Abolition of Limited Merits Review) Act 2017 (Cth).

after which the ACM reviews the draft plan against all applicable legal requirements. The Minister must incorporate the results of the review before adopting a final plan, and the efficient costs of investments named in an approved plan may be included in tariffs (Dutch Energy Law, explanatory memorandum, arts. 3.34–3.36, 3.110). A feature of the current legislative proposal is a new requirement that operators disclose, within the investment plan itself, the extent to which they have been unable to accommodate connection and transport requests and what investments they intend to make to address the shortfall – explicitly intended to give system users’ connection and capacity requests more direct influence over investment decisions than under the prior framework (Dutch Energy Law, explanatory memorandum).

Germany applies a genuine *ex ante* application-and-approval process, distinct from the notification-based capital cost mark-up described in Section 7.1, specifically to research and development expenditure: a network operator seeking to include R&D project costs in its revenue cap must apply by 30 June of the year before the costs are to be recovered, with the application required to contain sufficient information for a knowledgeable third party to assess whether the approval conditions are met without needing further information; any resulting approval is time-limited and made subject to a right of revocation if the approved funds are not used as specified in the approval decision (Bundesnetzagentur, 2025, item 17). This is a much more traditional *ex ante* approval procedure than the mark-up notification process, and its coexistence with that lighter-touch mechanism within the same regulatory framework is itself an illustration of the point made in Section 7.1: German regulation does not apply a single *ex ante/ex post* philosophy uniformly across all categories of investment, but calibrates the intensity of *ex ante* scrutiny to the specific type of expenditure involved.

7.3 Prudency and efficiency tests

Prudency and efficiency tests in various forms, underpin investment governance across most of the jurisdictions in this review. The “prudent investment” standard, asks whether an investment reflected a reasonable decision by the regulated firm at the time it was made; if so, the firm is entitled to recover a return of and on that investment’s original cost regardless of how circumstances later unfold (Joskow and Schmalensee, 2025). In the NEM, the AER will assess whether proposed CAPEX is prudent and efficient (NER 6.5.7(c)).

Simshauser and Akimov (2019) explain that a pure prudent-investment test is a low bar rarely failed in practice, since it is unusual for a utility to make a blatantly imprudent commitment, whereas a pure used-and-useful test can expose investors to substantial uncompensated stranding risk; most regulatory frameworks in practice, including Australia’s, apply a combination of both. Australia’s capital expenditure criteria – efficient cost, prudent operator cost, and realistic demand forecast – are a direct structural echo of the US prudent-investment doctrine, assessed *ex ante* at the point of forecast acceptance and revisited *ex post* through the RAB-reduction and CESS mechanisms discussed in Sections 6.5 and 7.1 (Csereklyei and Kallies, 2026).

Benchmarking (see also 5.4), provides an efficiency standard that regulatory proposals can be assessed against. All jurisdictions display some type of prudency or efficiency test. For example,

the Dutch Energiewet prescribes in Article 3.107/2.110 that only efficient costs that are necessary for the network operator to meet their regulatory requirements, will be considered in the Authorities tariff setting. Similarly, Ofgem (2026) provides guidance for the development of business plans to include evidence of cost efficiency as compared to historical benchmarks and/or benchmarking with comparators, as well as details of assumptions and justifications.

7.4 Cost-benefit analysis requirements

Formal cost-benefit analysis (CBA) requirements are the primary mechanism by which investment governance regimes attempt to test whether a proposed project is actually needed and represents the best available option, rather than merely being affordable within an approved revenue envelope. Vilaplana, Yang and Ackom (2025), reviewing CBA guidelines across the electricity sector internationally, describe a generic structure common to most frameworks, closely following European Commission guidance for major investment projects: defining project goals and stakeholders, quantifying and monetising direct and indirect impacts, discounting those impacts over the project's lifespan, and using sensitivity or probabilistic analysis to characterise the resulting uncertainty, with CBA capable of being applied *ex ante* (before a project starts), during implementation or *ex post* (after completion). Australia's RIT-D is a fully worked national example of this generic template: it requires the identification of a need expressed in output rather than technology terms, the identification of a set of "credible options" that must include non-network alternatives where feasible, comparison of each option against a defined counterfactual base case, and selection of whichever option maximises the present value of net economic benefit (NEB) across defined cost and market-benefit categories – including, since 2024, greenhouse gas emissions reduction as a recognised class of market benefit (Csereklyei and Kallies, 2026).

7.5 Contingent projects and reopeners

Reopener mechanisms allow a revenue determination to be revisited within a regulatory period to accommodate investment needs that could not reasonably have been forecast when the determination was set, addressing the information-timing problem introduced in Section 2.1. Australia's NER distinguish three categories with materially different procedural treatment: planned investments identified in the five-year economic forecast; cost pass-through events, for genuinely unforeseen and urgent needs such as natural disasters, assessed under a streamlined 90-day application process without a full RIT-D; and contingent projects, defined as needs that are "foreseen, but uncertain" in timing or cost at the time of the original forecast, which must be flagged with trigger conditions in the original economic forecast and, once triggered, processed through a defined application and public consultation procedure within statutory timeframes (Csereklyei and Kallies, 2026). A further, rarely used pathway allows a network to apply to revoke and substitute an entire distribution determination for major unforeseen CAPEX exceeding 5 per cent of the RAB in the first year of the period; the only distribution-level example identified in the material reviewed – a 2024 Jemena application – was ultimately withdrawn (Csereklyei and Kallies, 2026).

Ofgem expressly preserves reopeners in its RIIO-Framework decisions. A guidance document sets out the criteria under which these can be applied for. The most recent discussion around RIIO-ED3 confirmed a clear ongoing need for reopeners, especially in the context of climate resilience, but also seeks to limit and clarify their use. Overall, Ofgem is committed to funding the majority of network investment *ex ante*, with flexibility achieved through better strategic planning and proactive investment, rather than an *ex post* approach (Ofgem, 2025).

The Netherlands illustrates a related but distinct reopener logic operating through TenneT's transmission-linked costs rather than through a formal contingent-project category: certain TenneT costs passed through to Dutch DSOs have historically been determined *ex ante* with a two-year lag, requiring DSOs to pre-finance the gap without compensation, while other costs – specifically those linked to energy transition investment and the feed-in of decentralised generation – are determined *ex post* rather than forecast in advance (Nillesen and Pollitt, 2026). Read together with Pollitt, Duma and Covatariu's (2025) warning that frequent reopener use can erode the credibility of *ex ante* controls and raise the cost of capital, this suggests that reopener and contingent-project mechanisms are indispensable for accommodating the demand, technology and policy uncertainty identified as a core characteristic of network investment in Section 2.2, but the more often they are used, the more they blur the *ex ante/ex post* distinction this section opened with, and the harder it becomes to say which category a given jurisdiction's regime actually belongs to.

Finally, it is worth flagging a more fundamental critique of *ex ante/ex post* investment governance found in this literature, rather than treating the mechanisms above as settled best practice. Ben-David (2026) argues that the AER's current approach to Australian CAPEX regulation – requiring the regulator to conduct its own *ex ante* assessment of the efficiency and prudence of a network's proposed capital expenditure, essentially attempting to counter-forecast the firm's own forecast – is structurally unnecessary, and proposes a mathematically modified version of the CESS (Section 6.5) that would make network operators fully accountable for the accuracy of their own forecasting and delivery, removing the regulator's need to conduct *ex ante* prudence and efficiency assessments at all. The specific proposed redesign, however, is set out at a conceptual level without a worked analysis of its economic or implementation consequences, and should be read as a provocative reframing of the problem rather than a fully specified policy alternative. It crystallises a question this section's material leaves open: whether the elaborate *ex ante* approval architecture described in Sections 7.2–7.4 is a necessary response to genuine information asymmetry, or whether better-designed *ex post* incentive mechanisms could substitute for much of it.

8. Risk Allocation and Remuneration

Before turning to the specific risks below, it is worth being explicit about what “risk allocation” means in this context and who can actually bear a given risk, since the term is used loosely elsewhere in this review. A network investment risk materialises whenever an outcome relevant to cost recovery or profitability turns out differently from what was assumed when a price or revenue was set – for example, demand comes in higher or lower than forecast, a project costs more to build than expected, or an asset stops being needed altogether. Regulatory design determines who absorbs the financial consequence when that happens, and in the jurisdictions covered by this review that party is typically one of three: the network operator and its shareholders, who absorb (usually partly) a risk when regulation lets realised outcomes reduce the firm’s profitability without a corresponding adjustment to allowed revenue; consumers, who absorb a risk when a true-up, pass-through or reopener mechanism adjusts prices or future allowances to reflect what actually happened, meaning the network’s revenue is protected but consumers ultimately pay for the deviation; or, in a small number of cases discussed later in this section, a third party such as the state, where a mechanism is deliberately designed to shift a risk away from both the network and consumers. No allocation is free of trade-offs: shifting a risk onto the network operator sharpens its incentive to manage that risk well, but raises its cost of capital and, ultimately, the price consumers pay for a given return; shifting a risk onto consumers lowers the network’s cost of capital but leaves consumers exposed to volatility the network may be better placed to manage or absorb. Each of the risk categories below should be read with this basic three-way choice, and its associated trade-off, in mind.

8.1 WACC and financeability

The weighted average cost of capital (WACC), applied to the regulatory asset base to determine the allowed return on capital, is the single parameter that most directly connects a jurisdiction’s risk allocation choices to its remuneration outcomes. Every risk this section discusses is, in principle, compensated for either through the WACC itself or through a separate, more targeted mechanism, and getting this division wrong in either direction has real consequences – too generous a WACC transfers wealth from consumers to investors on every dollar of the RAB. As KPMG’s (2018) calculation, reported by Kuiper (2024), shows, where a WACC set even one percentage point above a network’s actual financing cost can generate significant additional annual profit; too low a WACC risks undermining the firm’s ability to finance the investment programme regulation is meant to secure.

“Financeability” is the distinct, narrower concept that operationalises this second concern: Ofgem defines it as the ability to secure financing in a “timely way and at reasonable cost”, and both Ofgem and Ofwat operate under statutory duties to have regard to financeability, using it as a formal secondary check on WACC and capitalisation-rate decisions – assessed, in Ofwat’s case, through specific credit metrics such as cash interest cover and notional gearing (Frontier Economics, 2017). The Frontier Economics report (2017), prepared for Australian regulatory consideration, notes explicitly that the existing NER regulatory framework has no equivalent

financeability concept, and that the AER's historical consideration of firm "insolvency" is a materially narrower test than financeability as applied in the UK – a genuine design gap between the UK and Australian approaches to WACC-adjacent risk management.

The WACC also interacts with risk in a subtler way than simply setting the overall return: Brunekreeft and Rammerstorfer's (2020) formal model, introduced in Section 6.4, shows that a regulated firm's true cost of capital is itself endogenous to how much operating-cost risk it bears, since a firm can lower its own risk profile, and therefore its true financing cost, by shifting spending from risk-bearing OPEX toward CAPEX – meaning a WACC calculated from historic capital-market data may not accurately reflect a firm's true current cost of capital once this rebalancing behaviour is accounted for.

8.2 Regulatory asset base treatment

How the RAB itself is rolled forward from one period to the next is a further risk-allocation lever, distinct from the level of the WACC applied to it. Australia's building-block approach takes the closing RAB from the preceding period, indexes it for inflation, adds new capital expenditure, and deducts depreciation and asset disposals to arrive at each year's closing value, with the *ex post* prudence and CESS mechanisms of Sections 6.5 and 7.1 (Csereklyei and Kallies, 2026).

Germany's RAMEN Strom reform varies this mechanic within a period rather than only between periods, introducing capital cost mark-ups that allow new investment made after a period's base year to be added into the revenue cap during the period itself, rather than waiting for the RAB to be reset at the next determination (Bundesnetzagentur, 2025) – a more flexible RAB treatment than Australia's.

8.3 Forecast risk

Forecast risk – the risk that the demand, cost or policy assumptions underpinning a revenue determination turn out to be wrong – sits upstream of most of the other risks in this section and is, in this literature, treated as inherently difficult to allocate cleanly to either the network operator or consumers, since it originates before the other risk categories in this section (demand, construction, stranded asset) even come into play, and shapes how those subsequent risks are experienced by both parties. Simshauser and Akimov (2019) trace Australia's 2004–2018 RAB expansion, and the subsequent 2010–2015 demand contraction that followed it, directly to forecast error compounded by reliability standards that were tightened in anticipation of demand growth that did not eventuate (Section 7.3). Ben-David (2026) frames the underlying problem more structurally: the current Australian framework requires the AER itself assess the reasonableness of a network's own capital expenditure forecast, creating what he terms a misalignment of responsibilities and risks – the regulator bears the analytical burden of second-guessing a forecast it did not make and cannot fully verify, which creates "incentives for network operators to exaggerate their capital expenditure requirements" (p 19), rather than genuinely allocating forecast risk to whichever party is best placed to manage it.

8.4 Demand risk

Demand risk – the risk that realised sales volumes differ from those assumed when a price or revenue was set – is allocated by design through the basic choice between price cap and revenue cap regulation introduced in Sections 5.1 and 5.2: under a price cap, the firm bears demand risk directly, since its revenue moves with actual volumes at the fixed price; under a revenue cap, that risk is shifted toward consumers and the regulatory settlement process through volume true-up mechanisms, leaving the firm’s revenue largely protected from demand fluctuations within a period. Because revenue cap regulation is the dominant model among the jurisdictions in this review (Section 5.2), demand risk in most of these systems falls more heavily on consumers and the regulator’s forecasting competence than on the regulated firm itself – which is precisely why forecast risk (Section 8.3) and demand risk are so closely linked: a revenue cap does not eliminate the consequences of a bad demand forecast, it simply relocates who bears them.

Söderberg and Vesterberg (2023), argue that a revenue cap regime facing rising demand uncertainty – which Section 2.2 identifies as an inherent feature of the energy transition – may produce exactly the under-investment outcome that Section 2.3 identifies as one of investment regulation’s core risks to guard against, even though the revenue cap was nominally designed to protect the firm’s revenue from demand risk. Söderberg and Vesterberg (2023) also note that a lower firm debt ratio provides protection against demand uncertainty and suggests that the regulator may either compensate the DSO directly for the increased demand risk, or incentivise the DSO to use equity rather than debt to finance their assets.

8.5 Construction risk

Construction risk – the risk that a project costs more, or takes longer, to build than assumed when it was approved – receives comparatively little direct attention in this review’s corpus. In distribution networks, construction risk is rarely borne unilaterally by the firm. For example, Australia’s NER framework routes part of the unforeseen or higher-than-expected costs toward consumers by design: cost pass-through events (NER 6.6.1) allow a defined set of unforeseen costs — regulatory changes, natural disasters, and similar triggers — to flow directly into the revenue determination; contingent projects (NER 6.6A.1–6.6A.2), covering needs that are foreseen, but uncertain in timing or cost, are added to the RAB once a trigger event occurs; and even genuine capex overspend against forecast is only lightly penalised under the Capital Expenditure Sharing Scheme’s Bright-Line Tiered Test, which applies just a 30% sharing ratio to the network on any overspend — leaving the remaining 70% to be recovered from consumers through the RAB. Construction risk in this setting is therefore less a risk the network bears than one substantially pre-allocated to consumers by the regulatory design itself.

8.6 Stranded asset risk

In Australia, the ACCC’s 2018 Retail Electricity Pricing Inquiry found evidence of network over-investment and recommended voluntary government write-downs of the RAB in Queensland, Tasmania and for Essential Energy (NSW), with rebates for the partially privatised NSW networks

(to be passed onto the consumers) - but implementation depended on individual state governments acting voluntarily, and none did; six years later, no write-down had occurred as reported in Kuiper (2024) quoting the ACCC. The NER contains no compulsory stranding mechanism the AER can invoke unilaterally. However, we note that the AEMC is currently exploring the allocation of risk, including stranded asset risk in its Electricity network regulation review, Package 2 (AEMC 2026).

In the context of supporting anticipatory network investment, Germany's regulator expressly states that concerns about stranded assets in the distribution system are overstated, as the needed expansion of networks to facilitate DER is already delayed (Bundesnetzagentur, 2025). This aligns with the observation by ACER, which shows that most (85%) of member states expect higher annual investment needs in the future. (ACER, 2026)

8.7 Regulatory commitment

Regulatory commitment – the credibility of a regulator's undertaking not to revisit past decisions opportunistically – was introduced in Section 2.1 as a foundational objective of investment regulation; it is considered specifically as a remuneration issue, since a lack of credible commitment is, in effect, a risk that must be compensated for through the WACC (Section 8.1) if it cannot be eliminated through governance design (Section 7).

Where regulatory commitment is credible and stable over time, investors can price capital on the basis of the regime as designed rather than on the risk of its unilateral revision, which is generally understood to lower the cost of capital and support more efficient long-term investment. Regulatory stability is accordingly treated across the jurisdictions considered in this review not as an end in itself, but as an instrument for keeping network investment affordable for consumers over the long run.

9. Third-Party and Non-Network Solutions

9.1 Competitive procurement

Where a network operator determines that a non-network (“non-wires”) solution is the most efficient way to meet an identified need, the literature considers competitive procurement mechanisms as the primary tool used to secure it transparently and at least cost, rather than leaving the network operator to select or self-supply the solution. Burger, Schneider, Vilim and Chatterjee (2019, Part 2) argue that where a distribution network operator is not fully unbundled from competitive activities such as DER ownership or aggregation, an independent third-party market operator, or at minimum closely monitored open standards and third-party bid review, is necessary to prevent foreclosure of non-network competitors – citing Pacific Gas and Electric’s use of an independent third party to solicit non-wires-alternative bids and an “independent evaluator” to review them as a working example from California. European distribution flexibility markets illustrate a more decentralised procurement model operating at scale: third-party platforms such as NODES (originating in Norway, now also used in Germany, Sweden and Great Britain), Piclo Flex (used by UK Power Networks and SP Energy Networks to run competitive tenders for flexibility from EVs, gas engines, batteries, biomass and commercial demand response) and GOPACS (used by Dutch DSOs including Liander) allow network operators to competitively source both short-term (“ShortFlex”) and long-term, tendered (“LongFlex”) flexibility capacity from third-party providers, rather than building network capacity to cover peak congestion (Beckstedde and Meeus, 2023).

9.2 Distributed energy resources and provision of contestable services

The regulatory treatment of DER ownership by network operators, as well as the provision of new competitive energy services such as provision of charging infrastructure by networks, is a live and only partially settled question across the jurisdictions in this review. US state regulators have generally sought to restrict distribution network operator ownership of DERs on competition grounds. However, Burger et al. (2019, Part 1) report that the California Public Utilities Commission and the New York Department of Public Service permit DER ownership by network operators (with some limits as to what kind of projects and how many) at least in part, by the view that DNOs/DSOs may be better positioned than competitive providers to deploy DERs under certain circumstances.

Burger et al. (2019, Part 1) cautioned against broader network-operator DER ownership for “market development” purposes, reasoning that network operators may develop informational and learning advantages that could crowd out the development of third-party competitive provision the regulators are otherwise trying to encourage – recommending targeted subsidies for third-party providers as an equally effective and more transparent alternative. FERC has separately clarified, that DERs may earn revenue from both regulated network services and competitive wholesale markets simultaneously, provided the system operator remains independent of the DER owner – a structural safeguard, rooted in what Burger et al. (2019, Part 1) term the “Bell Doctrine”

of quarantining monopoly activities from competitive ones, that recurs across most of this section's material in different guises.

Csereklyei and Kallies (2026) similarly flag active tension between networks' interest in providing contestable services such as kerbside EV charging infrastructure directly. Networks contend that competitive third-party providers are not available in particular locations, or cannot deliver the services they propose to deliver fast enough or at the same scale. On the other hand, third-party providers' argue that networks are using ring-fencing waiver processes to exclude them from an emerging market, without a clear regulatory answer yet as to whether non-network solutions should formally become part of the suite of services a network itself provides, and if so how such services should be incentivised relative to conventional capital investment. This mirrors the broader CAPEX-bias problem introduced in Section 6.4: the underlying concern in both cases is that a network's institutional and financial incentives still point toward capital investment even where a competitively provided or third-party alternative would be more efficient, and connection policy is simply the point at which that tension is currently most visible in the Australian material reviewed.

In a related discussion, Lowder and Xu (2020), reviewing DER integration in the US distribution system for the National Renewable Energy Laboratory, trace how the proliferation of customer-sited, third-party-owned DERs – predominantly rooftop solar, accelerated by net metering policy, federal tax incentives and falling technology costs – has put pressure on the traditional cost-of-service ratemaking model described in Section 4.1, since third-party-owned DERs sit outside the utility's own rate base and can impose real operational costs on the network that are not offset by any corresponding rate-base return, a dynamic utilities and regulators describe as revenue erosion and cross-subsidisation between DER and non-DER customers (Lowder and Xu, 2020, citing NARUC, 2016).

9.3 Demand response and flexibility services

Regulatory mechanisms specifically designed to make demand response and flexibility services financially attractive relative to conventional network augmentation vary considerably in maturity and apparent effectiveness across this review's jurisdictions. Australia operates two dedicated schemes for this purpose – the Demand Management Incentive Scheme (DMIS) and the complementary Demand Management Incentive Allowance Mechanism (DMIAM), which funds DNSP research and development of non-network solutions – but Csereklyei and Kallies (2026) find that both operate at a much smaller scale than the CESS and EBSS discussed in Section 6.5, require more complex evidence of benefits to access, and have consequently seen relatively slow uptake, leaving non-network solutions at a practical disadvantage against conventional capital augmentation despite being formally encouraged by the same regulatory framework. This is consistent with the TOTEX-versus-separated-CAPEX/OPEX distinction from Section 6.2: Kuiper (2024) and the AEC (2023) both point to Great Britain's TOTEX approach as more naturally incentivising an efficient mix of capital-intensive and flexibility-based solutions than Australia's separated framework, since a TOTEX regime removes the relative financial penalty a network faces for choosing a non-network, more OPEX-like solution over a capital one.

European experience shows flexibility services increasingly organised around formal congestion management, rather than only demand-response programmes in the traditional sense. Germany replaced its earlier feed-in management regime, under which renewable generators were curtailed in real time at the cost of their own lost revenue, with “Redispatch 2.0” in October 2021: a schedule-based process requiring all generation and storage facilities above 100kW to provide congestion management services, with system operators selecting providers by imputed cost and compensating them for lost revenue and imbalance costs (Beckstedde and Meeus, 2023). The Netherlands has gone furthest in formalising the mandatory/voluntary and short/long-term dimensions of flexibility sourcing: the Dutch DSO Liander, for instance, operates both short-term flexibility markets (via the GOPACS platform, with voluntary or mandatory participation variants) and long-term connection agreements with and without day-ahead curtailment rights. Beckstedde and Meeus (2023) map these choices explicitly onto a mandatory/voluntary by short-term/long-term matrix, noting that the optimal choice likely depends on local network characteristics such as topology, voltage level and the underlying cause of congestion. This body of work also flags an emerging TSO–DSO coordination problem specific to flexibility: transmission and distribution operators may compete for access to the same flexible resources for different purposes (congestion management versus balancing), creating both a competitive tension and a need for sequencing or cooperation mechanisms that existing European regulation, such as the System Operation Guideline allowing DSOs to refuse flexible resources’ participation in TSO balancing markets on technical grounds, has only begun to address.

10. Comparative Synthesis

10.1 Drivers of regulatory differences

Four distinct forces recur across this review as explanations for why jurisdictions that face broadly similar underlying engineering and economic problems have nonetheless arrived at different regulatory designs.

Constitutional and legal starting points: The clearest driver is the constitutional allocation of regulatory authority itself. The United States' genuine federalism leaves distribution regulation to fifty separate state commissions operating under state law, producing the heterogeneity documented throughout Sections 4–8, most starkly in Joskow's (2024) finding that the pace and form of performance-based regulation adoption varies state by state with no unifying national standard. Australia's cooperative federalism achieves a single national rulebook only through continuing intergovernmental agreement rather than constitutional authority (Section 3.3), a structurally more fragile basis for uniformity than it might first appear. Germany, while also a federation, has followed a more centralised model of regulation, which is made possible by wider powers for the federal parliament set out in the German Basic law, than for the US or Australia. Great Britain and the Netherlands, do not face this question at all, which likely helps explain why both operate single, long-standing national regulators with comparatively stable institutional architecture relative to the US and Germany.

Depth of regulation and feasible instrument choice: How many firms a jurisdiction regulates materially constrains which regulatory instruments are statistically or administratively viable. Germany's 800-plus distribution system operators support intensive, multi-method efficiency benchmarking (Pollitt, 2026); Norway's 123 firms support benchmarking with rich conditioning variables (Bjørndal et al., 2018); but Great Britain's 14 DNOs and Australia's 13 DNSPs cannot support domestic CAPEX benchmarking of comparable statistical power, pushing both jurisdictions toward more firm-specific cost assessment layered on top of benchmarking applied (Section 5.4). This is a case where a jurisdiction's regulatory design is constrained by market structure rather than a deliberate regulatory choice.

Path dependency from a small number of influential early reforms: Great Britain's 1990 privatisation and RPI-X framework, and its 2013 shift to TOTEX-based RIIO regulation, recur as reference points across almost every section of this review – not because British practice is necessarily superior, but because it was early, well-documented, and has been explicitly used as a template, positively or critically, by regulators and advisers elsewhere. Australia's building-block model was itself originally modelled on the UK's price cap approach before the UK evolved structurally (Section 4.1; Csereklyei and Kallies, 2026). A number of works reviewed here explicitly cited Ofgem's menu regulation and/or TOTEX reforms as models worth considering (AER, 2023; Kuiper, 2024; Frontier Economics, 2017). This suggests that observed convergence in the language of incentive regulation across jurisdictions should not be mistaken for convergence in substance: the same reference model can be adopted selectively, adapted structurally, or rejected outright, and this review has documented examples of all three.

EU legal integration as a distinct, non-market driver: For Germany and the Netherlands, EU directives establish a shared floor of regulatory objectives and National Regulatory Authority powers that neither the US nor Australia possess any supranational equivalent to (Section 2.3, Section 3.1). While Great Britain has left the EU with Brexit, it has been an influential driver of EU regulation in the energy space, and continues to share a common legacy with the other EU examples. This is a genuinely distinct driver of regulatory similarity, operating through binding legal obligation rather than through the voluntary policy learning and emulation described immediately above, and it explains why the three European jurisdictions in this review, despite real differences in regulatory model and instrument design, share a more similar underlying legal architecture for regulatory objectives and National Regulatory Authority independence than either shares with the US or Australia.

10.2 Relationship between institutional settings and regulatory choices

The individual findings above point toward a more general proposition: institutional setting does not directly determine regulatory model choice, but it does determine which regulatory choices are administratively and legally available, and this availability constraint does much of the explanatory work in this review.

This review found that federalism influences how regulatory design choices are made. The US's constitutional federalism produces genuine diversity in whether and how far individual states have moved from COSR toward PBR (Section 4.3); Australia's cooperative federalism, despite arising from a similarly decentralised constitutional starting point, produces a single national model precisely because the NEM's intergovernmental agreement was designed to override that starting point (Section 3.3). In Germany, a centralised model is more readily enabled by the specific distribution of powers set out in the German Constitution, the Basic Law. The lesson is that federalism as a constitutional fact matters less than the specific intergovernmental or legal mechanism through which network regulation is (or is not) centralised.

Ownership structure, does not appear to predict regulatory model choice in any consistent way either. Australia applies the same National Electricity Rules to privatised (Victoria, South Australia), partially privatised (two of three NSW distributors) and fully government-owned (Essential Energy, Queensland) networks alike (Section 3.5); the US displays the widest ownership diversity of all – investor-owned, municipal, cooperative and federal entities – coexisting under materially different governance but often facing the same state-level regulatory choices available to any utility in that state. This suggests that, at least among the jurisdictions and evidence reviewed here, the regulatory model applied to a network is chosen largely independently of who owns it.

10.3 Effectiveness of different approaches

This review has deliberately sought out evidence on delivered outcomes, not only design intent, and the resulting picture is considerably more mixed than a simple ranking of regulatory models would suggest.

A general finding is that incentive regulation, properly designed and consistently applied over a long enough period, can deliver real efficiency gains; and that “effective” and “equitably distributed” are not the same finding, and a regulatory design can be genuinely effective on the first dimension while remaining contested on the second (Jamans and Pollitt, 2007).

Where outcome evidence is design-specific rather than general, effectiveness claims should not be generalised across jurisdictions. Great Britain’s TOTEX reform is credited by some with successfully eliminating CAPEX bias (Frontier Economics, 2017) – but Pototschnig and Rossetto’s (2024) EU-level assessment finds this outcome depends on the regulator genuinely holding the CAPEX-OPEX ratio fixed, a condition not reliably met even in other schemes that describe themselves as TOTEX-based. The authors claim that the effectiveness of TOTEX regulation is a property of specific implementations, not of the TOTEX label itself. This qualification matters directly for the Australian debate this review is intended to inform, since TOTEX reform is often invoked there (including in the accompanying Csereklyei and Kallies, 2026 report) as an available fix for the capital bias documented in Sections 6.4 and 6.5 – the evidence here suggests that adopting TOTEX terminology would not, on its own, guarantee the outcome its advocates expect.

Where a design choice’s effectiveness depends on a variable outside the regulator’s direct control, outcomes can diverge from intent in ways the design did not anticipate. Söderberg and Vesterberg’s (2023) finding that Swedish DSOs facing greater demand uncertainty set lower prices specifically under ex-ante revenue-cap regulation, not under the prior ex-post regime, is the sharpest illustration of this in the review: a revenue cap is designed to protect network revenue from demand risk, yet the empirical evidence suggests it can still produce a price-suppression effect that risks under-investment precisely when investment needs are least certain and potentially greatest – the opposite of what the mechanism was designed to achieve (Section 8.4). This finding deserves more weight in the Comparative Synthesis than a single-country empirical study might normally receive, because it directly undercuts an assumption – that revenue caps straightforwardly protect networks from demand risk and therefore support adequate investment – that much of the rest of this review’s discussion of price versus revenue caps (Section 5.1–5.2) otherwise takes for granted. This points to the need to consider potential regulatory reform within context.

Australia’s own incentive framework offers this review’s most direct evidence of a design failing to achieve harmonised outcomes across its component instruments, documented in detail in the accompanying Csereklyei and Kallies (2026) chapter on incentive regulation inefficiencies. The AER’s own final decision in its 2023 review of all incentive schemes acknowledges in writing that the growing gap between the EBSS and CESS sharing ratios “may distort incentives by encouraging cost shifting from OPEX to CAPEX”, yet the same review left the DMIS and DMIAM – the schemes intended to counterbalance the CESS’s capital bias – essentially unexamined, despite a statutory requirement under NER clause 6.5.8A(d) that the AER consider the interaction of the CESS with any other incentives when developing it. This is a case where the regulator’s own evidence and legal mandate point toward a need for a more integrated redesign, and the actual outcome was incremental, scheme-by-scheme adjustment as already flagged in Csereklyei and Kallies (2026).

11. What does this mean for the future design of the NEM's investment frameworks?

This review's comparative evidence carries several implications for how the NEM's own investment frameworks might be reconsidered.

Regulatory design is context-dependent. Different jurisdictions have evolved differently to address broadly the same underlying problem, and no single model reviewed here can be read as a universally superior template; what works in one institutional setting does not transfer automatically to another.

Flexibility matters, particularly under transition conditions. A continuously evolving investment task calls for a regulatory process that can adapt as conditions change. Ofgem's experience is instructive here: it was able to flexibly adapt and revise its frameworks, rather than relying on piecemeal adjustments.

Path dependency can be overcome. Germany, the Netherlands and Great Britain have all made fundamental changes to the underlying structure of how network investment is regulated, in contrast to Australia. This was partly enabled by these jurisdictions' regulatory frameworks being less bound by overly detailed and prescriptive rules, which in turn gave their regulators greater flexibility to act. Australia, by contrast, is bound by a highly detailed and prescriptive electricity market regulatory frameworks (the NER), and this brings considerable rigidity and path dependency into the system. The level of detail in the NER now anchors the system and is itself a source of that path dependency, making it more difficult to flexibly respond to challenges (see also Csereklyei and Kallies, 2026).

Design choices operate within constraints. It nonetheless needs to be recognised that any regulatory design choice is made within constraints set by the overarching regulatory environment, and any proposals for reform need to acknowledge these constraints rather than treat the design space as unconstrained.

TOTEX illustrates the point. The long-debated, but ultimately discarded, shift to a TOTEX framework is a case in point: a TOTEX approach may be a useful, but not on its own sufficient approach for designing incentive regulation fit for future-ready networks. The comparative experience reviewed here suggests that a more conceptual redesign of the incentive system is advisable, rather than adopting TOTEX terminology in isolation.

Departures from theory may be necessary. Finally, the experience surveyed in this review shows that while regulatory frameworks should be derived from theory, practical considerations and transition pressures – including consumer protection concerns – may require departures from that theory, for example where networks are engaging in competitive services.

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Appendix: Abbreviations and acronyms

Acronym	Meaning
ACCC	Australian Competition and Consumer Commission
ACER	European Union Agency for the Cooperation of Energy Regulators
ACM	Autoriteit Consument & Markt (Authority for Consumers and Markets, Netherlands)
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AR-PST	Australian Research in Power Systems Transition
ARegV	Anreizregulierungsverordnung (Incentive Regulation Ordinance, Germany)
AU\$	Australian dollars
BNetzA	Bundesnetzagentur (Federal Network Agency, Germany)
CAPEX	Capital expenditure
CBA	Cost-benefit analysis
CEER	Council of European Energy Regulators
CEPA†	Cambridge Economic Policy Associates
CESS	Capital Expenditure Sharing Scheme
COLS	Corrected Ordinary Least Squares
COSR	Cost-of-service regulation

Acronym	Meaning
CPI / CPI-X	Consumer Price Index / CPI minus efficiency factor X (Australian term for RPI-X)
CRC	Cooperative Research Centre
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Cth	Commonwealth (Australia)
DEA	Data Envelopment Analysis
DER	Distributed energy resource(s)
DMIAM	Demand Management Incentive Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNO	Distribution network operator (Great Britain)
DNSP	Distribution network service provider (Australia)
DPCR4 / DPCR5	Fourth / fifth electricity distribution price control (Great Britain)
DSO	Distribution system operator
DTe	Dienst uitvoering en toezicht Energie (former Dutch energy regulator, predecessor to ACM)
EBSS	Efficiency Benefit Sharing Scheme
EC	European Community (as in Directive 2009/72/EC)
ED1 / ED2 / ED3	First / second / third RIIO electricity distribution price control (Great Britain)
EnWG	Energiewirtschaftsgesetz (Energy Industry Act, Germany)
ESC	Essential Services Commission (Victoria)

Acronym	Meaning
EU	European Union
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission (US)
FOCS	Fixed-OPEX-CAPEX-share
GasNEV	Gas Network Tariff Ordinance (Germany)
GOPACS	Grid Operators Platform for Congestion Solutions (Netherlands)
IQI	Information Quality Incentive
IRM	Innovation Roll-out Mechanism
kW	Kilowatt
LCNF	Low Carbon Network Fund
MYRP	Multi-year rate plan
NARUC	National Association of Regulatory Utility Commissioners (US)
NEB	Net economic benefit
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NIA	Network Innovation Allowance
NIC	Electricity Network Innovation Competition
NMa	Netherlands Competition Authority
NREL	National Renewable Energy Laboratory (US)

Acronym	Meaning
NSW	New South Wales
NVE	Norwegian Water Resources and Energy Directorate
Offer	Office of the Electricity Regulator (Great Britain, 1989–1998)
Ofgem	Office of Gas and Electricity Markets (Great Britain)
Ofwat	Water Services Regulation Authority (England and Wales)
OOR	Output-oriented regulation
OPEX	Operating expenditure
ORG	Office of the Regulator-General (Victoria)
PBR	Performance-based regulation
PIMs	Performance Incentive Mechanisms
R&D	Research and development
RAB	Regulatory asset base
RACE for 2030	Reliable, Affordable Clean Energy for 2030
RAMEN Strom	Regulierungsrahmen und Methode der Anreizregulierung für Elektrizitätsverteilernetzbetreiber (regulatory framework and incentive regulation methodology for electricity distribution network operators, Germany)
RIIO	Revenue = Incentives + Innovation + Outputs
RIIO-1 / RIIO-2	First / second generation of RIIO price controls
RIT-D	Regulatory Investment Test for Distribution
ROR	Rate-of-return (regulation)

Acronym	Meaning
RPI / RPI-X	Retail Price Index / RPI minus efficiency factor X
RvS	Raad van State (Council of State, Netherlands)
SA	South Australia
SFA	Stochastic Frontier Analysis
SIF	Strategic Innovation Fund
SSEN	Scottish and Southern Energy Networks
StromNEV	Electricity Network Tariff Ordinance (Germany)
TOTEX	Total expenditure
TSO	Transmission system operator
UK	United Kingdom
UKPN	UK Power Networks
US	United States
WACC	Weighted average cost of capital



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