Australian Government
Productivity Commission

Electricity Network Regulatory Frameworks

Productivity Commission Draft Report
Volume 1

October 2012

This is a draft report prepared for further public consultation and input. The Commission will finalise its report after these processes have taken place.

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The Productivity Commission

The Productivity Commission is the Australian Government's independent research and advisory body on a range of economic, social and environmental issues affecting the welfare of Australians. Its role, expressed most simply, is to help governments make better policies, in the long term interest of the Australian community.

The Commission's independence is underpinned by an Act of Parliament. Its processes and outputs are open to public scrutiny and are driven by concern for the wellbeing of the community as a whole.

Further information on the Productivity Commission can be obtained from the Commission's website (www.pc.gov.au) or by contacting Media and Publications on (03) 9653 2244 or email: maps@pc.gov.au

Opportunity for further comment

Electricity regulation is a complex area. This Commission is releasing this draft report to encourage further comment and scrutiny from participants. You are invited to comment on this draft inquiry report in writing and/or by participating in the public hearings, as shown below. Anyone interested in participating in a public hearing should contact Jill Irvine on (02) 6240 3223 or Christine Underwood on (02) 6240 3262.

Please send written responses to the Productivity Commission by **23 November 2012**. If possible, please provide submissions by email (electricity@pc.gov.au).

Public hearings will commence on the **26th November**, with the venues to be advised. For those participating in the public hearings, the Commission would appreciate receiving advance copies of submissions or a brief summary on the main discussion points at least **2 working days** prior to the relevant hearing date. Subject to demand from participants, the Commission may add further hearings. If these are required, details of any additional hearings will be published on the Commission's website.

The final report will be prepared after submissions have been received and public hearings have been held, and will be forwarded to the Australian Government by 9 April 2013.

Commissioners

For the purposes of this inquiry and draft report, in accordance with section 40 of the *Productivity Commission Act 1998*, the powers of the Productivity Commission have been exercised by:

Philip Weickhardt	Presiding Commissioner
Wendy Craik	Commissioner

Terms of reference

I, Wayne Swan, Deputy Prime Minister and Treasurer, pursuant to Parts 2 and 3 of the *Productivity Commission Act 1998*, hereby request that the Productivity Commission undertake an inquiry into electricity network frameworks, focussing on benchmarking arrangements and the effectiveness of the application by network businesses of the current regulatory regime for the evaluation and development of interregional network capacity in the National Electricity Market (NEM).

Background

Australia's electricity sector is facing a number of challenges over the coming years. This includes a large investment requirement for networks to replace ageing assets, meet growing levels of peak demand, reliability requirements and to facilitate the transition towards Australia's clean energy future.

Recent increases in network expenditure, and the resultant flow on to increases in electricity prices for end users, have highlighted the need to ensure networks continue to deliver efficient outcomes for consumers. Network regulation is a complex task requiring difficult and technical judgements. This inquiry will inform the Australian Government about whether there are any practical or empirical constraints on the use of benchmarking of network businesses and then provide advice on how benchmarking could deliver efficient outcomes, consistent with the National Electricity Objective (NEO). In addition, a second stream of this inquiry will examine if efficient levels of transmission interconnectors are being delivered, to inform the Australian Government about whether the regulatory regime is delivering efficient levels of interconnection to support the market.

Scope of the Inquiry

The Commission is requested to assess the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure to meet the long term interests of consumers, consistent with the NEO. In addition, the Commission is requested to assess whether the current regulatory regime, as applied to interconnectors, is delivering efficient levels of network and generation investment across the NEM.

In undertaking the review, the Commission should:

- examine the use of benchmarking under the regulatory framework, incorporating any amendments introduced in the review period, in the National Electricity

Rules and provide advice on how different benchmarking methodologies could be used to enhance efficient outcomes; and

- examine whether the regulatory regime, with respect to the delivery of interconnector investment in the NEM, is delivering economically efficient outcomes.

In undertaking the inquiry, the Commission should consider and take into account the work that is currently being progressed through the Standing Council on Energy and Resources, the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The Commission should have particular regard for the AEMC reviews into transmission frameworks, power of choice (demand side participation) and the suite of rule changes relating to network regulation currently under consideration by the AEMC in accordance with its statutory obligations.

The Commission should engage with the AEMC, the AER and the Australian Energy Market Operator in undertaking the review. In addition, the Commission should consult with Australian Government agencies, state and territory government agencies and other key stakeholders in undertaking the review.

The Commission will report within 15 months of receipt of this reference and will hold hearings for the purpose of this inquiry. The Commission is to provide both a draft and a final report, and the reports will be published. The Government will consider the Commission's recommendations, and its response will be announced as soon as possible after the receipt of the Commission's final report.

Wayne Swan

Deputy Prime Minister and Treasurer

[Received 9 January 2012]

Acknowledgement of referee

The Commission engaged the services of Dr John Tamblyn, a well-known expert on the National Electricity Market (who has recently been involved in two other independent reviews of aspects of the electricity industry) to review some draft chapters and the overview for this report. Dr Tamblyn provided valuable feedback to the Commission, for which we are most grateful. However, the views and judgements in this report are those of the Commission alone, and should not be attributed to Dr Tamblyn or any other participant, except where clearly stated.

Disclosure of interests

The *Productivity Commission Act 1998* specifies that where Commissioners have or acquire interests, pecuniary or otherwise, that could conflict with the proper performance of their functions during an inquiry they must disclose the interests.

Dr Craik has advised the Commission that she is the beneficiary of subsidised solar PV panels.

Contents

The Commission's report is in two volumes. **This volume 1 contains the Overview, Draft Recommendations and findings and chapters 1 to 8.** Volume 2 contains chapters 9 to 21 and the appendices. Below is the table of contents for both volumes.

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Abbreviations and explanations

Abbreviations

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEMA	Australian Energy Market Agreement
CAIDI	Customer average interruption duration index
CAPEX	Capital expenditure
CBA	cost-benefit analysis
CDF	Customer Damage Functions
COAG	Council of Australian Governments
CPI-x	Consumer Price Index minus a benchmark productivity rate (x)
CPP	Critical Peak Price
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DANCE	Dynamic Avoidable Network Cost Evaluation model
DG	Distributed generation
DLC	Direct load control
DM	Demand management
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DNSP	Distribution Network Service Provider
DRED	Demand Response Enabling Device

DSP	Demand side participation
ESCOSA	Essential Services Commission of South Australia
ETC	Electricity Transmission Code
EU	European Union
GDP	Gross Domestic Product
HV	High voltage (nominally 5–22kV)
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRSR	inter-regional settlement residue
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
LRMC	Long Run Marginal Cost
LV	Low voltage
MAIFI	Momentary average interruption frequency index
PSCR	Project Specification Consultation Report
MAR	maximum annual revenue
MCE	Ministerial Council on Energy
MDMS	meter data management system
MED	Major event days
MW	megawatt
MVA	megavolt amperes
MWh	megawatt hour
NECF	National Electricity Customer Framework
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NEO	National Electricity Objective
NEL	National Electricity Law
NER	National Electricity Rules
NGL	National Gas Law
NMS	network management systems

NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
N-x	
Ofgem	Office of Gas and Electricity Markets (UK)
Ofwat	Office of Water Services (UK) (On 1 April 2006, the functions of Ofwat were replaced by the Water Services Regulation Authority)
OPEX	Operating expenditure
PC	Productivity Commission
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCER	Standing Council on Energy and Resources
STPIS	Service Target Performance Incentive Scheme
SOC	State-owned corporation
TNSP	Transmission network service provider
TOU	time of use (electricity tariffs)
VCEC	Victorian Competition and Efficiency Commission
VCR	Value of Customer Reliability
WACC	Weighted average cost of capital
WAPC	weighted average price caps

Explanations

Billion	The convention used for a billion is a thousand million (10^9).
Findings	*Findings in the body of the report are paragraphs highlighted using italics, as this is.*
Recommendations	***Recommendations in the body of the report are highlighted using bold italics, as this is.***
Requests for further information	*Information requests are paragraphs highlighted using italics, as this is.*

OVERVIEW

Overview

The main messages

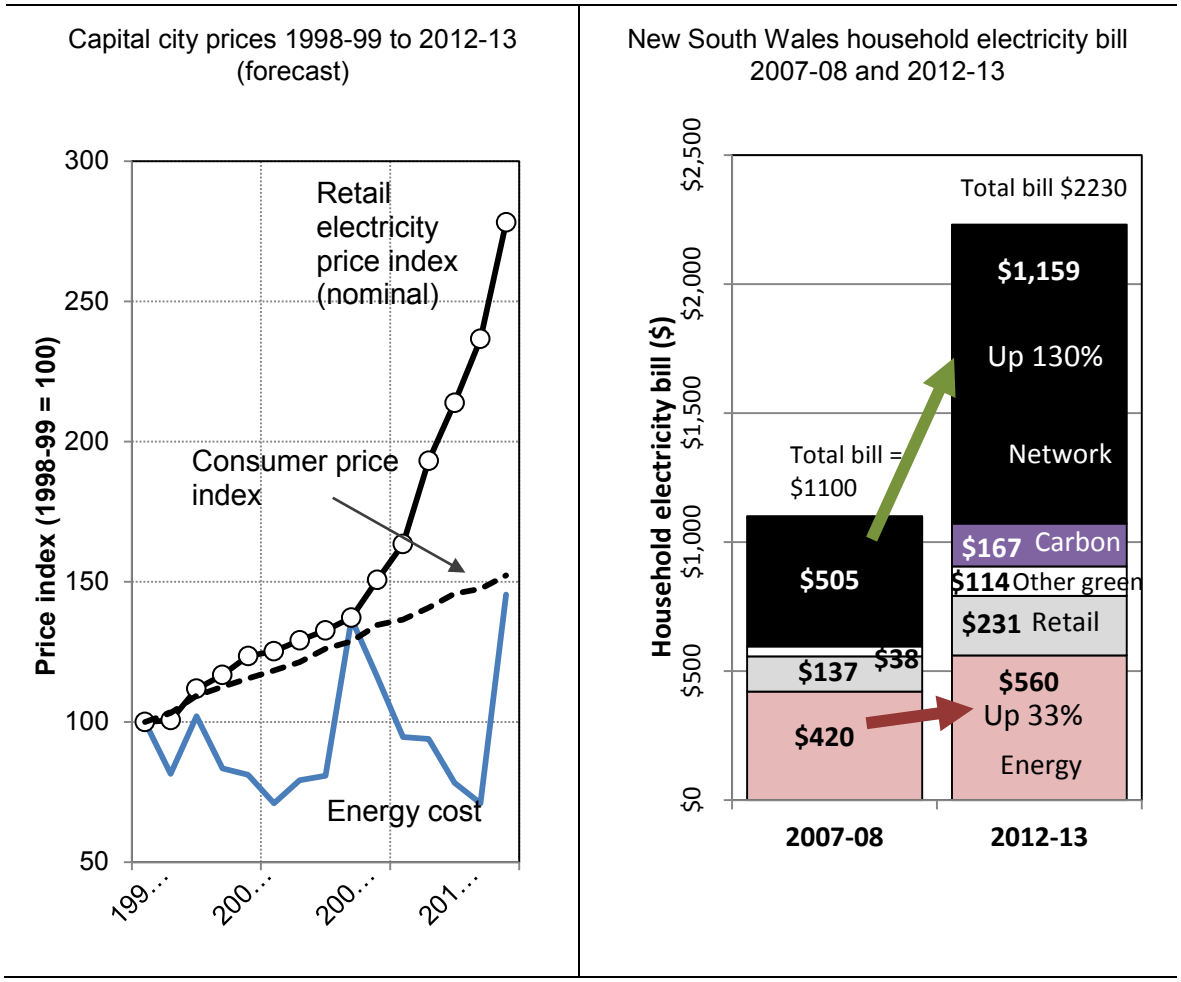
- Electricity prices have risen by more than 50 per cent in real terms over the past five years. Spiralling network costs are the main contributor to these increases, partly driven by inefficiencies in the industry and flaws in the regulatory environment.
- Resolving benchmarking and interconnector problems is worthwhile, but only as a component of a more fundamental, nationally-focussed, package of reforms that addresses the major, interlinked regulatory barriers to the efficiency of electricity networks, including:
  - a poor focus on consumers, despite their interests being the overarching objective of the regulatory regime
  - inadequate demand management
  - costly ways of achieving, and sometimes excessive, reliability requirements
  - state regulatory arrangements and network business ownership
  - the resourcing and capacity of, and structural arrangements for, the regulator
  - the regulatory rules, and the ability of the regulator to apply them.
- The overarching objective of the regulatory regime is the long-term interests of electricity consumers. This objective has lost its primacy as the main consideration for regulatory and policy decisions. Its pre-eminence should be restored by giving consumers much more power in the regulatory process.
  - Australian governments should create an industry-funded representative energy consumer body with the expertise to be an effective participant.
- Some 25 per cent of retail electricity bills are required to meet around 40 hours of critical peak demand each year.
  - Avoiding this requires a phased and coordinated suite of reforms, including consumer consultation, the phased removal of retail price regulation, and the staged introduction of smart meters, accompanied by time-based pricing for critical peak periods.
  - This would defer costly investment, ease price pressures on customers, and reduce the large hidden cross-subsidies from (often lower-income) people who do not heavily use power in peak times, to those who do.
- Reliability is critical to electricity networks, but some consumers are forced to pay for higher reliability than they value.
  - Reliability decisions should be based on what customers actually want, rather than by prescriptive (sometimes politically influenced) standards.

- State-owned network businesses have conflicting objectives. There is no evidence that these businesses outperform their private counterparts in terms of efficiently meeting the long-term interests of their customers. Indeed, there appears to be evidence to the contrary. Conflicting objectives also frustrate the effectiveness of incentive regulation for these businesses.
  - State-owned network businesses should be privatised.
- In progressing reform, the Australian Energy Regulator needs more resourcing, expertise, independence and accountability.
- The incentive regulation regime encourages businesses to build too much. Eliminating some obvious flaws would encourage more efficient investment, including:
  - ensuring the allowed rate of return on regulated assets is not excessive
  - ex post review of capital spending, when businesses overspend
  - no requirement that the regulator consider every detailed aspect of the businesses' spending proposals.
- At this stage, benchmarking — which compares the relative performance of businesses — is too unreliable to set regulated revenue allowances. Nevertheless, greater and more effective use of benchmarking could better inform the regulator's decisions
- There is no evidence of insufficient capacity in the interconnectors carrying power between jurisdictions, as sometimes alleged. In fact, they are underutilised because of perverse incentives created by the regulatory regime. Changes to pricing rules address these incentives.
- The gains from a package of reforms are significant. Indicative estimates suggest:
  - In New South Wales alone, $1.1 billion in distribution network capital expenditure could be deferred until the next five year regulatory period by adopting a reliability framework that took into account consumers' preferences for reliability. The actual savings are likely to be larger.
  - Adopting a different reliability framework for the high-voltage part of the network (transmission) could defer investment around $2 to 3 billion of investment across the national electricity market over the next five year regulatory period
  - Critical peak pricing would produce savings of around $100–$250 per household each year (after accounting for the costs of smart meters).
- While the gains from these reforms are large, they will not happen overnight — long-term investments and regulatory decisions have already been made. But future cost savings rely on reforms made now.
- In considering the benefits for consumers, it is important not to blame network businesses for the current inefficiencies. Mostly, they are responding to regulatory incentives and structures that impede their efficiency.

Why should we care about electricity networks?

Nationwide, retail electricity prices rose by around 50 per cent in real terms from June 2007 to June 2012. The rising costs of the electricity network — the wires, poles and other infrastructure used to transport power from generators to consumers — have been a major driver of these prices. Network costs are around 40–50 per cent of an average household's electricity bill, so any cost pressures on the network have a major impact.

Figure 1 **Prices have risen steeply**



Regulation plays a key role in these developments. While Australian governments have generally opened the generation and retailing segments of the electricity sector to competition, the network services remain natural monopolies and are subject to detailed government price and other regulation. This inquiry focuses on the National Electricity Market (NEM), which enables the trading of power throughout Australia, excepting Western Australia and the Northern Territory. It has several common features and institutions, including the:

- Standing Council on Energy and Resources (SCER), which replaces the previous Ministerial Council for Energy, and has representatives from the Australian Government and all states and territories. It is responsible for broad policy and the legislative framework for the NEM
- Australian Energy Market Operator (AEMO) which, among other roles, manages the transmission network and operates the spot market that determines wholesale energy prices
- the Australian Energy Market Commission (AEMC), which undertakes energy market reviews, provides policy advice to SCER, and sets the National Electricity Rules (the 'Rules')
- the Australian Energy Regulator (AER), which is the economic regulator for electricity and gas markets in the NEM.

The importance of the long-term interests of consumers — the objective of the national regulatory regime — has been under-emphasised. The 'National' in the NEM is also a work in progress — but progressing too slowly in the Commission's view.

State and territory governments, and their regulators, still play too large a role in setting reliability standards and in regulating retailing, and they also mandate other licence conditions for the network businesses. Additionally, they have various renewable energy policies that affect network businesses' options for efficiently addressing emerging bottlenecks in their systems. They are the owners of network services in Queensland, New South Wales, Tasmania and, in part, the Australian Capital Territory. They still own generators in New South Wales and Tasmania, and retailers in Tasmania and the Australian Capital Territory.

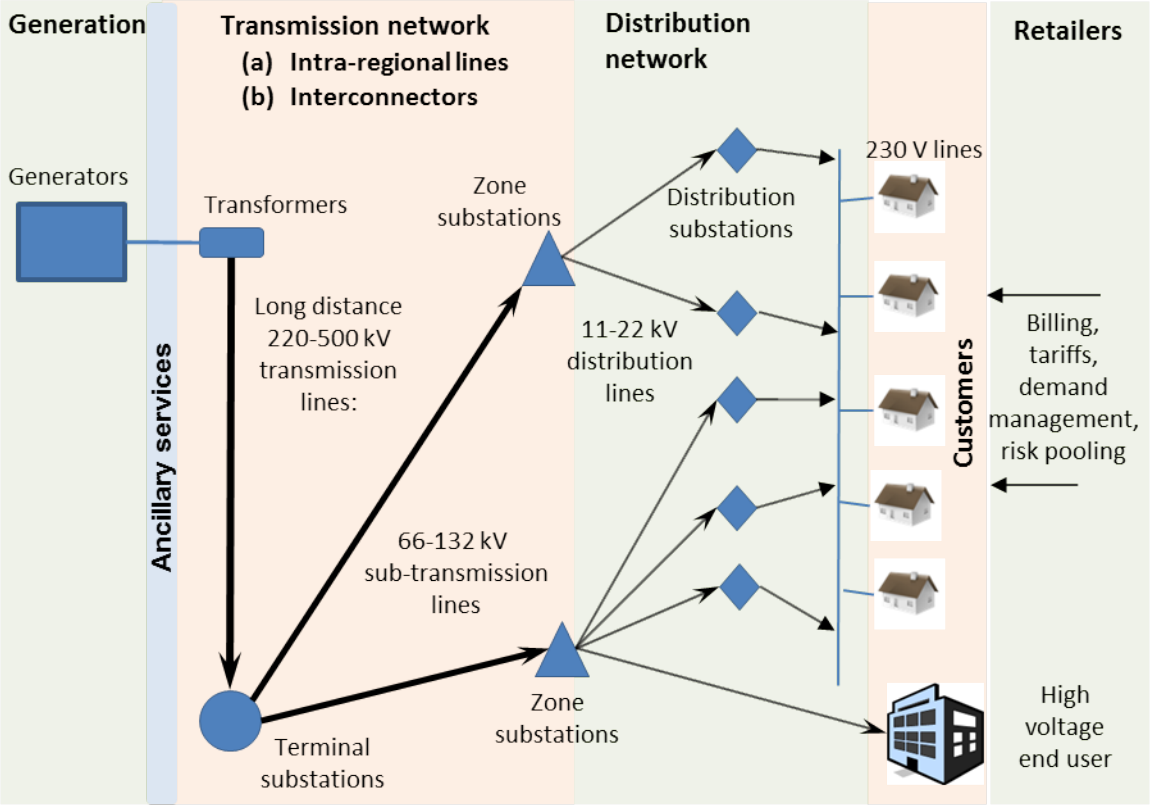
As a result, there is no nationally uniform regulation of network services in the NEM, with major variations in the treatment of the:

- distribution networks, the lower voltage capillaries that deliver power at the local level. The distribution networks account for the bulk of total network costs
- intra-regional transmission network, which comprises the high voltage components of the network that carry power over long distances within states
- inter-regional high voltage transmission network ('interconnectors').

Quite apart from the continued parochial mix of costly state-based regulations, the AER claims that the national regime is flawed too, and has led to inflated costs of capital and created incentives for inefficient investment, with flow-on price effects.

Some also identify future problems in the NEM arising from shortcomings in the regulatory arrangements for 'interconnectors'. The concern is that there is underinvestment in interconnectors, weakening the capacity for trading power across the network. Underinvestment could put more pressure on prices and undermine the efficient use of renewable energy generators.

Figure 2 **The electricity system**



The Australian Government has requested that the Commission consider these issues through two lenses:

- the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure. Benchmarking typically measures the costs or revenues of an efficient network business, with the regulator using the results as the standard for assessing whether any given network business's expenditure proposals are efficient and prudent. (An alternative benchmarking approach is to reduce each network business's allowable annual revenue by the productivity growth rate of an efficient firm — an approach already considered by the AEMC.)
- the effectiveness of regulatory arrangements for interconnectors.

This report includes extensive analysis of issues directly related to benchmarking and interconnectors. However, the Commission has found that it is not possible or desirable to look at those issues separately from the complex and interrelated regulatory system in which they sit. There is, in effect, no point in simply fixing a punctured tyre if the car has no engine.

Accordingly, the Commission has adopted a broader perspective, reflecting that outcomes in the NEM involve complex interactions between multiple influences: the National Electricity Rules; the behaviour of the regulator; the governance and culture of each of the regulated network businesses; and the impacts of many other (multi-jurisdictional) regulations and policies (figure 3).

There are many ongoing and intensive reviews of the NEM, most of which are focused on specific areas of major concern. The Commission has considered the evidence and analysis from these other reviews during the course of the inquiry. It will continue to do so for reviews that have not yet been finalised.

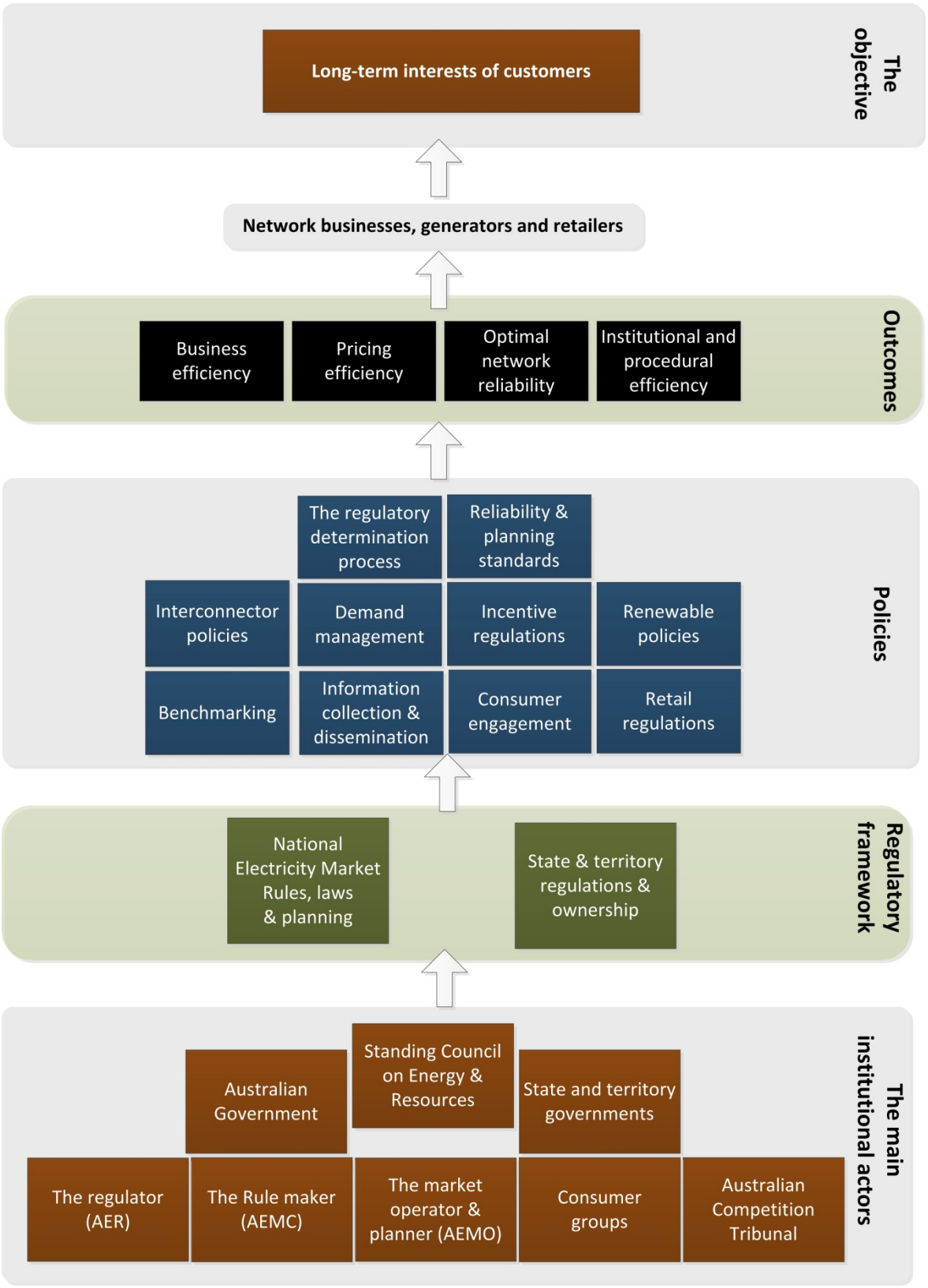
While recognising the predominant role of the AEMC as the 'Rule maker', the implementation of a coordinated package of reforms — as proposed by the Commission — suggests that it will be desirable to consider some adjustment to policy-making processes (as discussed later). This would avoid undue delays in reform.

Against the broader perspective adopted by the Commission, the overarching issue is whether the main policy objective behind the NEM — the promotion of efficient investment in, and efficient operation of, electricity services for the long-term interests of consumers — is being achieved and if not, why not? This motivates the key questions underlying this inquiry: why have network costs been rising, will they continue to do so, are the costs justified given the policy objective of the NEM, and if not, how can the problems be fixed?

Consumers have little voice in the regulatory regime

While the objective of the National Electricity Law is to meet the long-term interests of consumers, the involvement of consumers in the processes of the NEM has been partial and intermittent.

Figure 3 **Benchmarking is one (small) piece of a complex regulatory jigsaw**



Consumer groups have generally represented either major energy users or disadvantaged people. They have traditionally had some involvement in the AER's regulatory processes — primarily in attempting to decrease network charges or to develop better arrangements for disadvantaged consumers. They have proposed changes to the Rules, submitted to AER network determinations and participated in some Australian Competition Tribunal hearings of appeals to AER determinations.

However, the smaller advocacy groups do not have many resources to do this, and do not believe that the Tribunal has given much weight to their views (the panel evaluating the limited merits review regime suggested that they are treated as 'inconvenient guests'). In general, network businesses have not sufficiently engaged with consumers, even in matters where they have aligned interests (such as addressing reliability problems or introducing smart meters and the smart grid). The AER has also not engaged well with consumer groups — an observation emphasised by the inquiry into the limited merits review regime.

There are strong grounds for improving information flows to consumers — such as through the public availability of benchmarking results, and information on the various cost drivers of electricity bills.

Equally, there is merit in a single consumer body with expertise in the economic regulation of energy markets and, accordingly, the capacity to understand some of the complexities of the NEM and its investment and cost drivers. The body would need to represent *all* consumer groups, consistent with the objective of the National Electricity Law to promote the long-term interests of consumers.

This body could engage with NEM institutions in their processes and would give them the scope to participate in the negotiation of regulatory determinations with network service providers, a model that has apparently worked well in the United Kingdom and the United States. It would represent all household and business consumers — and not any particular constituency — and it would be headed by people selected on a merit basis. An advisory group representing the many diverse consumer groups would provide (non-binding) advice to the body.

As for some other institutions in the NEM, the body would be financed through a small ongoing levy on market participants (effectively amounting to a consumer levy). In addition to its major role as an informed and capable body with economic expertise, the body could also take over the functions currently performed by the Consumer Advocacy Panel. (The Panel is a grant-giving body, not one that participates in regulatory or appeals processes.) This would limit the proliferation of new bodies.

Are network expenditures inefficient?

There is a strong case that the efficiency of some network businesses could be improved. The Commission's analysis of several metrics suggests that there are significant differences in the performance of the various businesses. That should not be surprising. This is true for almost any industry. The difference, however, is that the usual competitive processes that weed out less efficient businesses are non-existent for regulated natural monopolies.

Some factors are (partly) outside the control of the businesses — which is why benchmarking of all relevant regulations (including those in states and territories and non-regulated policy influences) should play an ongoing role in monitoring the performance of network businesses.

Demand management is weak

Network and generation capacity is based on meeting peak, not average, demand (figure 4). Peak demand growth has been a key driver of investment in generation and network capacity in the last five years. Peak demand events occurring for less than 40 hours per year (or less than 1 per cent of the time) account for around 25 per cent of retail electricity bills.

The growth in household air conditioning is the major contributor to this pattern. A household running a 2 kilowatt (electrical input) reverse cycle air conditioner, and using it during peak times, receives an implicit subsidy equivalent of around $330 per year from other consumers who don't do this. Around two thirds of this subsidy reflects the high costs of augmenting electricity networks for very hot days, when air conditioner use collectively places enormous loads on networks.

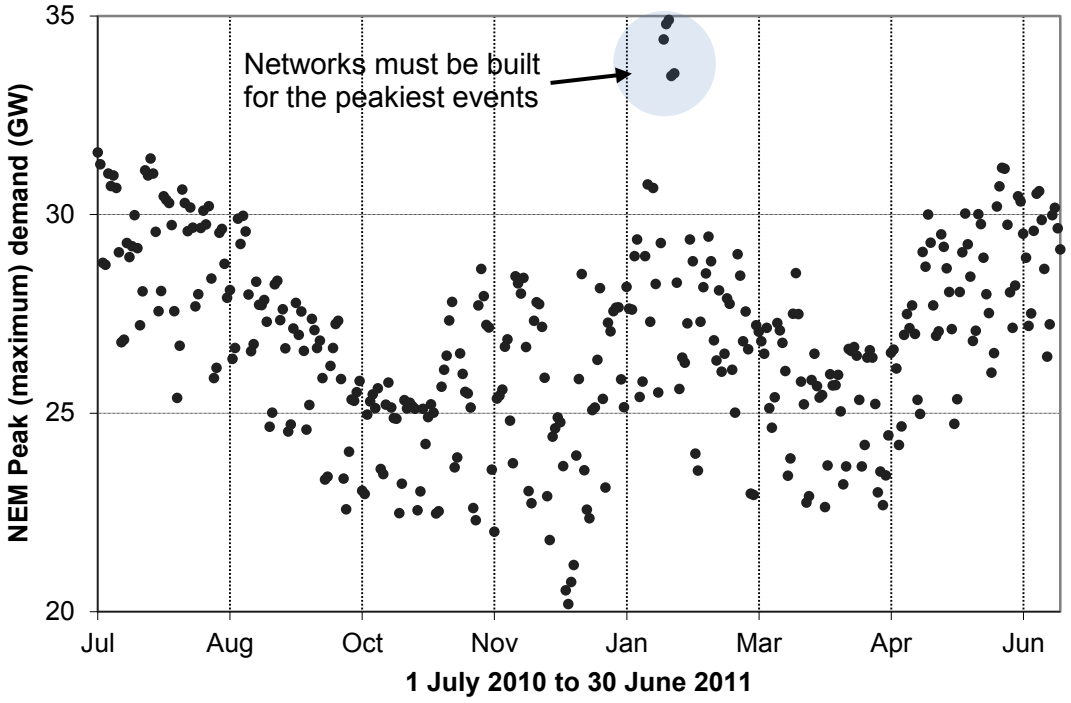
More generally, the costs of meeting peak demand through investment in generation and network augmentation are not fully borne by those using power at peak times. As a rule of thumb, supplying a 'peaky' consumer will be more than double the cost of supplying a 'non-peaky' consumer.

Critical peak pricing is already occurring for large energy-intensive users

Large industrial and commercial end users tend to have much flatter patterns of use and, at the margin, are a lesser contributor to peak demand. Most of these customers have the required metering, and some are already exposed to critical peak pricing. A first step would be to extend such pricing to the bulk of the remaining businesses in

this group. This could provide a relatively low cost and more rapidly achieved source of critical peak load reduction, especially for transmission assets.

Figure 4 **Networks must be built for the peakiest events**



Currently, networks (or parties acting on their behalf) pay some large industrial and commercial users to curtail their demand to relieve network constraints in peak demand periods. These arrangements could be extended to more businesses. As proposed in the AEMC's recent Power of Choice Review, a complementary change would be to allow reductions in load to be combined and offered by 'aggregators' to the NEM spot market.

The adoption of cost reflective pricing in households and small businesses is in its infancy

Households and smaller businesses are generally not exposed to time-based, cost-reflective network pricing. Thus, users are not encouraged to shift consumption away from peak demand periods, leading to hidden subsidies between peaky and non-peaky consumers, and over-investment in peak-specific investments. Currently, a low-income household without an air conditioner is effectively writing cheques to high-income users who run air conditioners during peaky periods.

Accordingly, reliance on supply side investment to meet growth in peak demand is inefficient, is inequitable in some cases, and drives network prices higher than they need to be. Many major players have supported a change in principle, including the NEM Rule maker (the AEMC) and all peak industry bodies representing the supply chain (the Electricity Network Association, the Energy Retailers Association, and the Energy Supply Association). Various consumer groups acknowledge the benefits, but are concerned about the risks for low-income consumers.

The savings appear to be significant. One business, AGL, estimated household savings from the phased introduction of smart metering and time-based charges of $1.6 billion annually. (The Commission has generally found smaller, but still important benefits if a cost-benefit based rollout process were adopted.)

Removing such buried cross-subsidies and reducing the required investment in the network (and peaking generators) cannot realistically happen quickly. The Commission's quantitative estimates show that any big-bang policy related to appropriate pricing would be likely to fail a cost-benefit test, as well as creating transitional costs. In contrast, a carefully managed approach has the potential to reduce price pressures significantly.

It is worth mapping out the desired end point — some years away — and then ensure there is an orderly transition. In the long run, appropriate network pricing requires several complementary policy changes, including:

- time-based pricing of network charges that reflect the underlying network costs — an uncontroversial principle for many. Such pricing would have to particularly apply to around 40 critical peak hours per year (whenever they occur). The network businesses would pass on these charges to retailers. To provide the right signals, retailers would need to reflect these charges in their tariff offerings to consumers
- the need to signal critical peak prices to consumers in advance — to encourage people to shift the time of their power use (hot days are predictable). In some cases, people may request that the distribution business or retailer control their key power-using appliances — mainly air-conditioning — during these peak hours ('peak load control'). For example, they may agree to have their air conditioner remotely controlled to cycle on and off during the critical peak period, thus maintaining reasonable comfort levels, while cutting costs. The pricing and revenue formulae used by the AER would have to preserve, or create, the right incentives for network businesses to undertake such demand management
- smart meters and associated technologies to determine people's electricity consumption over time (and to read people's meters remotely, without manual

inspection). People cannot be charged time-based prices unless network businesses receive real-time information about usage patterns. Furthermore, without additional policy action, peaky users would have an incentive to refuse smart meters to retain their cross-subsidies. The Commission's preferred approach to this problem is that in network areas where the installation of meters would deliver net benefits, all households should be required to have a meter. Alternatively, as a group, those without smart meters would have to have bear all the residual costs of peak use averaged over their tariffs and also fully bear the high incremental costs of reading their old meters manually

- the phasing out of retail price regulation, which would otherwise frustrate time-based charging and stifle retail competition and innovation. In particular, with the implementation of time-based network charges, any retailers that failed to adapt their business model and continued to embed significant cross-subsidies in their tariff offers would risk losing market share (including to new-entrant retailers)
- the use of weighted average price caps and changes to incentive regulation to remove the existing bias in favour of capital expenditure.

While specifying the long run is relatively straightforward, the transition involves tricks and traps. Any transition would require:

- the engagement of network businesses, retailers and especially consumers in the process, comprising provision of information, consultation, and a transition that takes into account the costs of change. (The process should take account of the lessons from the Victorian smart meter rollout, which experienced several major problems, and has made consumers wary of technological change in this area.)
- coordination by distribution businesses of the gradual rollout of smart meters to consumers within localised areas of their network. Rollouts should only occur in regions where there are looming network constraints. A NEM-wide rollout at a given time would be costly, and in many instances make no difference to the required investments, thereby producing negligible benefits. An essential aspect of any regional rollout should therefore be a cost-benefit test, which would need to take into account the investments needed to implement cost-reflective pricing; the degree to which a rollout would avoid or defer costly network infrastructure; the nature of the user charges the business could apply; and retailer and consumer responses. One of the critical benefits of this approach is that it can take account of policy decisions, learning from experiences elsewhere, and technological changes that might affect the payoff from demand management over time
- sensible transitional network charges. The transitional arrangements might include the initial use of poorly targeted 'time-of-use' tariffs, which only have

simple peak, off-peak and shoulder rates. While AusGrid's experiences in New South Wales show these do not achieve major network efficiencies, they might at least raise consumer awareness that costs vary over time and may ease the adjustment path. However, financial analysis suggests that the transition to critical peak pricing should not be too slow because the rewards from critical peak pricing are the major network savings. If the transition is too slow, then the Commission's quantitative assessment is that it would be better not to rollout smart meters in the medium term at all

- that retailers pass on time-based network charges to consumers, since this is an essential element of achieving a demand response. This is likely, but should not be assumed. Retailers could also offer complementary demand management services and technologies that reduce people's bills, while also relieving pressure on the network at peak times.

Given the importance of the transition and its relative complexity, the Commission proposes that the Council of Australia Governments, through the Standing Council of Energy and Resources, should oversight the process. However, it should avoid prescriptive approaches that do not take into account the cost-benefit framework described above.

Distributed generation

Distributed generation — which produces power close to the point of consumption — could potentially perform a similar role to demand management. It may sometimes help to relieve network congestion, meet peak demand or improve system reliability, thereby avoiding or deferring network investment.

However, the current policy environment sends opposing signals to distribution networks and consumers about the economic value of distributed generation. On the one hand, the capacity for local generation to substitute for network investment is constrained by regulatory obstacles, although some of these — such as a lack of information about network constraints and uncertainty about connection charges — have been, or are soon to be, substantially resolved.

On the other hand, various subsidies to certain types of distributed generation — particularly rooftop photovoltaic units — have led to unbalanced incentives and inefficiencies. The take-up of rooftop photovoltaic units has produced minimal network savings, as existing non time varying tariffs do not encourage householders to orient units to the west to maximise generation in periods of peak demand late in the afternoon. Moreover, the effective use of distributed generation to produce

network savings needs to ensure that take-up is maximised in those parts of the system subject to the greatest constraints.

Current subsidies to particular forms of distributed generators have had few benefits for the network and, in the face of carbon pricing, now play a redundant (and inefficient) role as a measure for reducing emissions. Governments should therefore phase out as quickly as practicable subsidies for rooftop photovoltaic units, other forms of distributed generation delivered via feed-in tariffs, and the small-scale component of the Renewable Energy Targets Scheme.

State and territory governments should change the feed-in tariffs for any uncontracted small-scale distributed generators exporting power into the grid, so that their tariffs reflect the market wholesale prices at the time of energy production, and the (net) value to network businesses from reducing loads on their equipment at critical peak periods.

Reliability standards are mostly too high

Ensuring reliable networks requires significant ongoing investment. As demand grows, reliability standards increase, or network infrastructure ages, network businesses must increase their investment — which ultimately customers must finance. However, there is a growing concern that some network reliability standards are too high (which some claim have reflected political responses to isolated major blackouts, rather than systemic problems), with costs that exceed consumers' willingness to pay. (Against that background, the AEMC is undertaking its own independent examination of reliability in transmission and distribution networks.)

The benefits of re-aligning standards to meet consumer preferences appear to be large and some benefits could be realised soon after jurisdictions agree to the new framework. For example, the Australian Energy Market Operator (AEMO) cited a proposed investment in New South Wales to meet a 'deterministic' standard that implied that customers valued their electricity at around $9 million per MWh (an estimated 150 times more than consumers would be willing to pay).

There are two principal sources of difficulty with reliability standards.

- Parochialism — there is no national framework for standards. Jurisdictions impose different reliability requirements (mostly uninformed by customer preferences), and measure reliability in different ways. The focus of network businesses and particularly transmission businesses — reinforced by history, organisational culture, an understandable desire to control outcomes, and

familiarity with local requirements — might rely too heavily on intra-state network solutions and ignore more efficient inter-state options.

- The price–quality tradeoff is invisible to most consumers — most are unaware of the high price they pay in their electricity bills for the super-reliability resulting from excessively stringent standards. (Equally, *were* a lower than optimal standard to be set, they would not know how much they would need to pay to improve it).

The way forward must take account of the fact that the reliability issues for distribution and transmission networks are different.

Distribution networks

Given the greater and more timely observability of reliability problems in distribution, it should be possible to relinquish current jurisdictionally prescribed input standards. Instead, the regulator should impose appropriate penalties (rewards) for businesses failing (exceeding) a reliability performance target, basing the incentives on clear evidence of customers' willingness to pay for reliability. This approach would aim to replicate the signals that customers in competitive markets send to suppliers about the tradeoffs between quality and price, allowing distribution businesses to take a commercial approach to their investments in reliability. This would lead to reliability outcomes at the local level that reflected local consumer preferences rather than prescriptive standards, and that would encourage efficient expenditure (including for non-network solutions).

The new incentive regime would build on the AER's existing Service Target Performance Incentive Scheme (STPIS), which penalises/rewards businesses for their reliability performance. As well as applying all components of the Scheme to distribution businesses throughout the NEM, the Commission proposes that incentives for performance be based on an up-to-date assessment of the value that the relevant mix of customers place on reliability. Bolstering the reporting requirements under the Scheme would also increase transparency and facilitate benchmarking. An amended STPIS would remove the need for jurisdictionally-based reliability requirements for distribution businesses.

Transmission networks

Unlike distribution networks, transmission networks rarely experience major problems. Problems in transmission can lie latent until major loads and coincident failures in generation or network equipment overstretch the system. The resulting

extreme power outages can then affect large populations and entail high costs. For example, in an international context, a major blackout in North America in 2003 led to power loss for up to two days for 50 million people, costing around $6 billion at that time and contributing to 11 deaths. The prospects of relying exclusively on an incentive scheme similar to the STPIS are weak because of the rarity of such events, the lack of good leading reliability indicators (and the potential financial inability of a network business to compensate consumers for the large damages experienced).

Another aspect of transmission networks is that power inputs into the network at any one point (say North Queensland) can affect transmission networks thousands of kilometres away. Interruptions or changes can have adverse impacts on other networks in the NEM, including major blackouts if the system becomes unstable. As the NEM becomes more interconnected, network effects are likely to increase. Reliability standards that are specific to a jurisdiction (or a network) do not consider these inter-jurisdictional network effects, and so current requirements that encourage transmission businesses to optimise only their own networks do not provide an efficient level of reliability.

It should be emphasised that there are no easy solutions for ensuring efficient transmission reliability and planning in the NEM (and indeed this is the experience internationally). All arrangements involve 'big brother' in one form or another, whether it be governments, a confederation of network businesses, or a single body. Compromises and judgments must be made. A combination of transparency, accountability, consultation, specialist knowledge, independent decision-making and giving pre-eminence to consumer preferences are the essential components of a workable arrangement. The AEMC have recently made recommendations to address the above problems. While there are significant overlaps between the Productivity Commission's and the AEMC's thinking in this area, on balance, the Commission prefers a different model to that favoured by the AEMC.

The Commission favours:

- developing a single NEM-wide reliability framework for transmission, which would make network planning more coherent and avoid some of the biases towards intra-regional transmission infrastructure compared with interconnectors or other solutions
- setting planning standards using the 'probabilistic approach' (in which the costs of an improvement in reliability are set against the assessed value to consumers of this improved reliability at the jurisdictional, or even more local level). This is simply a cost–benefit test

- a model that better caters for the varying value of reliability by region and customer type and need, rather than the present system where the required standards are often divorced from customer preferences
- involving a single planning agency for the entire NEM that is independent of individual governments and network businesses, which are conflicted in their role as planners and reliability setters. The Commission proposes AEMO as that agency. Under this model, AEMO, in close collaboration with each transmission business would use a probabilistic model to identify and specify augmentations, and use a cost-benefit test to select the most efficient investment. Introducing contestability for 'separable' augmentations of the network (as currently applies in Victoria and in parts of the United States) is appealing in principle. However, realising the potential benefits requires deep, contestable markets and low transaction costs. The Commission currently has insufficient evidence on the costs and benefits of contestability and accordingly is seeking further information. At this stage, the Commission recommends that the planner (AEMO), in consultation with incumbent transmission businesses, would identify and specify appropriate augmentations and non-network solutions and their timing. For large projects, the network businesses would be expected to manage and tender individual projects themselves, but the AER would approve the required revenue allowance before the project is due to commence. However, for small projects, only AEMO would be involved in negotiating the costs with the transmission businesses.

This approach does not involve significant uncertainty. It is similar to the model used in Victoria. However, under the Commission's model, AEMO would not exercise a procurement function for either separable or non-separable projects at this stage.

The gains of reform in this area are significant. The Commission estimates that an efficient transmission reliability framework could produce net present value savings in the realm of $1 billion within a single regulatory period, but much more over the long run.

However, some parties prefer a model in which businesses would meet so-called hybrid standards and make their own investment decisions, with AEMO playing an advisory role. Such an approach (which the AEMC supports) would be superior to the current arrangements outside Victoria and would reduce excessive investment. Its effectiveness would be bolstered by privatisation since, under incentive regulation, businesses would have a profit motive to choose the least costly approach. However, under the hybrid model:

- customers would not immediately benefit from the cost savings of the businesses, until the AER factored these into lower revenue allowances in future regulatory periods
- there would still be some of the costs associated with the use of deterministic standards, with the risks this poses for overinvestment, poorly allocated investment, bias towards intra-state rather than inter-state options, and levels of reliability exceeding those valued by consumers
- the gains could be weakened if state-owned transmission businesses are not privatised
- there is no independent determination of the type, scale and timing of investment needed to optimise the network.

If governments do adopt such an approach rather than the Commission's preferred alternative, the Commission proposes that there should be greater scrutiny by the AER of the measures intended to relieve constraints or deliver customer driven reliability standards. Where there is a discrepancy between the scope, specification and costings of AEMO and the transmission business then:

- during the revenue determination process, the AER, would accept AEMO's advice on the required revenue to fund the (big and small) investments necessary for reliability purposes, unless the transmission business can show why its alternative was more efficient. This would require amendment of the Rules
- given this approach maintains incentive regulation, the network business may subsequently choose alternative investments than those proposed by AEMO.

The Commission is seeking feedback on the costs and benefits of its preferred approach compared with alternatives, and will take into account the AEMC's considerations of these issues in the final report.

State-owned enterprises

Transmission and distribution businesses in Tasmania, NSW and Queensland remain state-owned (and partly state-owned in the ACT), whereas network businesses in Victoria and South Australia are privately owned.

While governments have a legitimate role in owning and operating many services in Australia, the rationale for state-ownership of electricity network businesses no longer holds. This reflects the development of sophisticated incentive regulations that function best when the regulated businesses have strong cost-minimising and profit motives.

State governments often impose multiple constraints on state-owned corporations that are incompatible with the maximising returns to their shareholders. These constraints can include:

- social and environmental obligations
- requirements to procure locally
- a lack of coherence of governments in their dealings with the businesses over time. Governments may make decisions to reduce dividends when price increases are politically sensitive, limit capital spending when governments are concerned about debt levels, or encourage capital expenditure if there are pressures for greater reliability
- employee benefits and job security for employees that are out of kilter with those associated with most businesses
- poor governance, including appointment of board members on a non-merit basis.

For example, in New South Wales, the Acts governing the state-owned corporations include non-commercial goals, which, where appropriately justified, would be better met through explicit government regulation or budgetary measures. At a minimum, the objectives should be prioritised. For example, in New South Wales, s. 8 of the *State Owned Corporations Act 1989*, requires state-owned corporations to give equal weight to commercial success, social responsibility, ecological sustainability, and a sense of responsibility towards regional development and decentralisation.

State ownership can involve employee protection arrangements that would not be typical in most private businesses. For instance, in New South Wales, Ausgrid is required to provide a five-year employment guarantee to award staff and is subject to requirements to procure locally in some cases, a hidden cost which electricity consumers must bear.

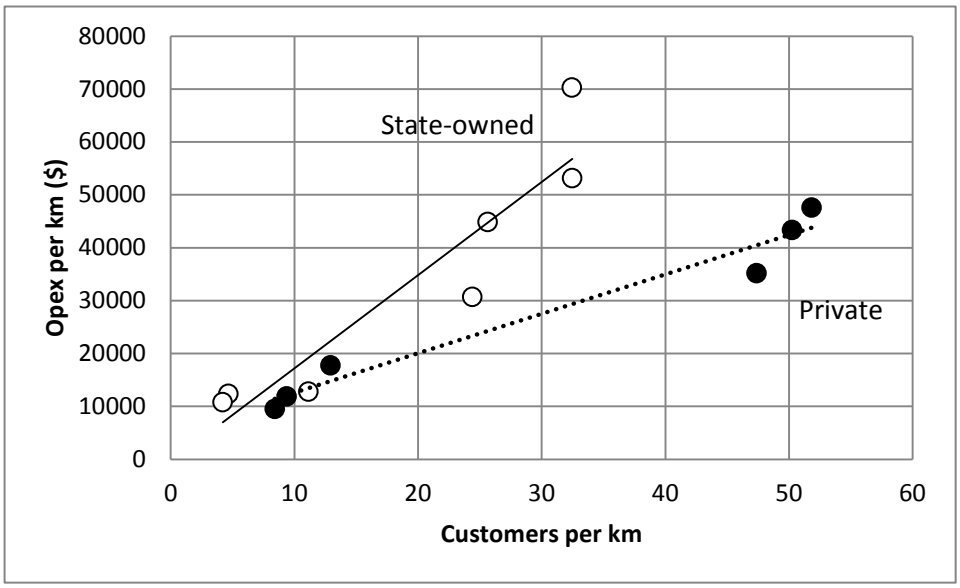
While analysis of relative efficiency is difficult, the empirical evidence suggests that, although some perform relatively well, as a group, the aggregate productivity outcomes of state-owned businesses are poorer than their private peers. This is likely to reflect the mixed incentives they face. Some participants in this inquiry claim that a risk-averse focus on 'building things' still permeates some of these businesses.

There are strong arguments for privatisation of these businesses. There is no evidence that the productivity, reliability, quality or cost performance of private sector electricity network businesses is worse than their public sector equivalents. To the contrary, the evidence in Australia and internationally suggests that such

private sector enterprises are more efficient. It should be emphasised that privatisation is not de-regulation. To the contrary, there is a symbiosis between regulation and privatisation. Strong regulation is needed to achieve the private provision of secure, reliable and appropriately priced electricity network services. And privatisation strengthens the effectiveness of incentive regulation.

Figure 5 **Operating expenses for state-owned and private businesses**

$ per kilometre of line



Privatisation is not a radical move. There have been few problems in Victoria or South Australia.

In the event that privatisation does not occur, there are strong grounds for different governance arrangements, with the goal of re-invigorating the original purpose of corporatisation of the old state-owned businesses. Among others, this includes merit-based appointment of all board members, public disclosure of ministerial directions, and the removal of non-commercial objectives and obligations (such as procurement and employment policies).

The critical role of the Australian Energy Regulator

The NEM involves multiple interested parties and institutions with clearly defined roles. Ensuring these institutions work well is critical to effective regulation and, in the context of this inquiry, to the degree of discretion that they may wield in using benchmarking, determining new rules and planning the network.

There are reasonable grounds for changing aspects of the governance of the AER, which is currently located within, and resourced by, the Australian Competition and Consumer Commission (ACCC). During the formation of the NEM, it was initially intended that the AER should be a standalone independent entity.

The regulator has not won the confidence of stakeholders, and perceptions of its performance have declined in recent years — as indicated in the AER's own surveys. The concerns about the agency assume several forms. One relates to the resourcing, processes and capabilities of the organisation. Some have claimed that it is overly legalistic, adversarial, insufficiently consultative, and that it does not have enough in-house expertise. The other concern relates to the degree of its independence, given its co-location in, and links with the ACCC.

Impressions of organisations by other stakeholders can be misleading, but these concerns have been raised by many diverse parties. The Commission understands that the AER is also aware of many of these issues, and has developed a strategy for addressing them. A first step in organisational change would be to undertake a small-scale and quick review to independently assess the nature and degree of any inadequacies, including the need for more resourcing and greater expertise in some areas.

On the governance issue, the Commission weighed up several options, of which the two most appealing were:

- leaving the AER inside the ACCC, but with independent control over its resources, and budget, and greater accountability about how it manages those resources (including through a separate annual report). The AER would publish its strategy for improving its performance and its relationship with stakeholders, and provide milestones against which to assess whether the strategy was working. This option recognises some of the benefits of co-location, including access to some of the ACCC's specialist expertise, the synergies with other aspects of utility regulation undertaken by the ACCC, and the capacity to move staff between the two bodies when there are peak demands (as occurs as new regulatory determinations are progressed). There are also budgetary benefits from sharing offices with the ACCC across the eastern states and territories
- removing the AER from the ACCC and creating a standalone independent energy regulator — an option suggested by many stakeholders in the Commission's consultations — and consistent with the original institutional arrangements envisaged for the National Electricity Market (and as raised in the most recent October meeting of the Standing Council on Energy and Resources). This would remove any perception that the ACCC unduly influences the AER, and would make it easier for it to be properly funded (as for AEMO) through a

levy on market participants. Such funding would assure that the agency would have a secure source of funding to undertake its regulatory functions (noting that these will grow as it assumes responsibility for regulation of energy retailing, and the additional functions outlined in this inquiry report). Separation would allow the AER to develop its own organisational culture, and under an appropriately constituted board, to exercise control over its recruitment, remuneration, performance management and accountability for effective processes and outcomes.

The choice between the two options appears finely balanced. The Commission's current position is to recommend the first option for the time being and assess whether that achieves the desired outcomes. This would take account of the non-trivial transaction costs of re-structuring (especially as major regulatory determinations are looming) and the loss of some positive synergies. However, the Commission is seeking feedback on this issue from stakeholders.

Another related issue is funding. While it appears that funding through a levy on market participants would most easily be achieved were the AER a separate regulator, the Commission understands that it may still be possible to fund the AER through an industry levy without separation. The desirability and feasibility of such a funding arrangement is uncertain — another area where the Commission invites the views of participants.

Incentive regulation is not working well

Incentive regulation and the regulator's forecasts of efficient costs

Under incentive regulations, the regulator forecasts efficient aggregate costs over the upcoming regulatory period (of usually five years), which it uses to set a revenue allowance for that period. The business makes higher profits if it reduces costs below those forecast by the regulator. In doing so, the business reveals the efficient costs of delivering the service, which would then influence the regulator's determination in the next period. Accordingly, incentive regulation encourages efficiency while reducing the risks that networks use their monopoly positions to set unreasonably high prices. Benchmarking — which measures a network supplier's efficiency against a reference performance — is just one way of assessing whether any given business's expenditure proposals are efficient.

The theory is fine; the reality is not. The regulatory arrangements underpinning incentive regulation are protracted, uncertain and costly, with the proposals and the regulator's determinations becoming increasingly detailed over time. The decision

documents for Victorian electricity distributors were around 450 pages in 2000, around 1000 pages in 2005 and 1800 pages in 2010 — reflecting the complexity of the proposals and the huge size of the network revenues involved (around $9 billion annually). The Rules that stipulate many of the requirements for proposals are also lengthy and subject to regular changes — currently more than 1300 pages, and now up to the 51st version in just six years. (The Rules most relevant to this inquiry are around 200 pages in length.) The approximate cost of one complete cycle of revenue determinations using the current approach is $330 million.

One of the *potential* advantages of more aggregated benchmarking of business costs (or, as the AER requests, more discretion) is that it might avoid the necessity for such complex proposals and determinations, and help overcome the information disadvantages a regulator has in dealing with the minutiae of a business's cost structures. However, given claims about systemic flaws in the current Rules, a critical issue is whether the results from benchmarking or any other cost models would be pointless adornments to long reports, or would actually constrain inefficient network businesses' spending.

There are three main areas of concerns about the Rules, all of which have a bearing on benchmarking.

Can the business circumvent incentive regulation?

Several aspects of the regulatory environment — one a function of the Rules, and the other a consequence of state-ownership of businesses — may collectively have unwittingly frustrated the purpose of incentive regulation.

Some businesses have spent much more than the regulator's revenue allowance. Any excess capital spend (capex) is rolled into a business's Regulatory Asset Base at the next regulatory determination. While it cannot recover revenue to meet the cost of this additional capex during the relevant regulatory period, the business can earn a return on that excess capex for the remaining (usually long) life of the assets.

Though hard to substantiate, there is reasonable concern that:

- the weighted average cost of capital used to determine allowances may have been too high, reducing the penalty from overspending (and sometimes making it commercially attractive)
- the investment decisions of state-owned corporations may be distorted by easier access to finance than their private peers. The states apply competitive neutrality charges on debt and tax equivalent payments on the network companies. However these flow back to state treasuries which, as shareholders may take a

different view to those of private companies. From a whole-of-government perspective, the usual strong discipline of shareholders to constrain overspending is weakened. Certainly, it appears that state treasuries have recently been prepared to fund capital overspending of their network businesses. This appears to be in contrast to most private shareholders which, given recent equity and debt markets, would have found it very difficult, if not imprudent, to have adopted a similar strategy.

The incentives for what some call 'goldplating' would be weakened if the regulated rate of return on capital is 'correct' and if the AER were to introduce an incentive arrangement that provides consistent incentives to reduce capital expenditure costs throughout the regulatory period (a so-called 'efficiency benefit sharing scheme'). Nevertheless, where a business exceeds the amount of forecast spending in the regulator's final determination, there are compelling grounds for the AER to re-assess the efficiency and prudence of the additional capital spending. The onus of proof should be shifted so that the business would need to show why consumers should bear the costs of expenditure overruns.

Do the Rules oblige the regulator to become bogged in a morass of detail?

Several informed commentators argue that the Rules require the AER to examine *all* elements of the proposals made by the businesses when making its determinations. There is some uncertainty about whether the Rules really do oblige the AER to behave this way. Nevertheless, the AER appears to act as though it is constrained, and the length and detail of the proposals and responses are consistent with this. For example, there have been debates about the efficient number of locks and keys, the length of insulated conductors and appropriate pole treatment processes.

If the AER must engage with the detail at this level, then it would severely constrain the capacity for many forms of benchmarking and other cost forecasting approaches to simplify the current system. For instance, the AER would have an uncertain capacity to use benchmarking in concert with other cost estimation methods to reach determinations on reasonable aggregate opex allowances.

Moreover, such a detailed approach leaves the AER exposed to merit review of any of the parts of a business proposal. Network businesses have a capacity to 'cherry pick' the aspects of a proposal where they believe the regulator is in error. In contrast, they obviously have little interest in revealing where the regulator has been too generous. In some instances, this has led to the situation in which a ruling has

been made on one aspect of the AER's determination to correct an error, while ignoring that such an error must have countervailing impacts on a related matter. (This has apparently applied to the way in which the weighted cost of capital is calculated.) The National Electricity Law gives little capacity for the regulator to address these interdependencies. Overall, the objective of the National Electricity Law — the long-term interests of consumers — appears to have been lost in what has become an elaborate legalistically framed process. There would be benefits in clarifying:

- the importance of the National Electricity Objective as a guiding principle for decisions in any merits review process
- the interdependence between some critical aspects of business costs.

An independent panel investigating the limited merits review regime has recently reported its findings and recommendations to the Standing Council on Energy and Resources (although at the time of finalising this report, the Commission has not examined the panel's review).

The reasonableness of the 'reasonableness criterion'

The AER has argued that it cannot set efficient revenue allowances because the Rules oblige it to accept the highest cost that just passes a reasonableness criterion, rather than using its best cost estimate. However, there are several counter perspectives:

- In using benchmarking and other approaches, the regulator has rejected business cost proposals in many cases, sometimes by large amounts, so it is hard to assess the degree to which it has actually been constrained.
- Some of the recent and very significant cost increases for distribution networks reflect decisions made in state-based regulatory environments, and cannot be attributed to the Rules.
- Any cost estimation method — benchmarking or otherwise — cannot ever measure the most efficient cost with precision. The likelihood of error with even the 'best' regulatory estimates is (exactly) 100 per cent. Assuming that the problems that encourage cost padding are resolved (as discussed below), under-remuneration is likely, ultimately, to lead to larger costs than over-remuneration of an equal magnitude. This is because the costs of underinvestment affect the long-run provision of reliable network services to consumers. In contrast, if the incentive regime were performing its role, any over-remuneration would not lead to over-investment by a well-governed, profit-motivated network company. Rather it would result in slightly larger profits

(which have lower efficiency costs), which the regulator could reduce in subsequent regulatory periods.

This suggests there should be the retention of some bias towards encouraging investment, but not too large a one. Benchmarking (triangulated with other information) is compatible with this approach so long as the regulator uses a standard for assessing business performance that is not at the best practice frontier — leaving room for regulatory error.

However, in keeping with desirability of avoiding assessment of every detail of a business proposal (as discussed above), the Commission considers that the AER should only be required to test the 'reasonableness' of the overall expenditure proposals.

The AER has requested a rule change through the AEMC to address the various deficiencies in the regulatory regime, including much greater scope for discretion. The AEMC's consideration of this matter is ongoing but they appear to be sympathetic to the AER's rule change request (reflected in a recently released draft determination). The Productivity Commission is also sympathetic to some aspects of the Rule change request, but considers that regulatory discretion needs to be tempered. Certainly, as discussed further below, aggregate benchmarking by itself would be a fragile basis for exercising discretion.

The role of benchmarking

Supposing that the flaws in the regulatory regime were corrected, including privatisation and some major Rule changes, the question remains about the role of benchmarking.

At this stage, and given the difficulties outlined in box 1, benchmarking is not sufficiently reliable or robust to set regulated revenue allowances. A particular concern is that it is difficult to distinguish between inefficiency and errors arising from model misspecification, poor data, different regulatory settings and varying operating environments.

Box 1 The difficulties with benchmarking

While benchmarking methods are often sophisticated, there are many problems in applying them and uncertainties about the accuracy and robustness of the results:

(a) There are many different methods for estimating 'efficient' costs. They revolve around the assumption that unexplained differences in the performance of firms reflect managerial inefficiency. Different approaches can result in divergent measures of efficiency — which may not be a sound basis for regulating future revenue or prices.

(b) Incentive regulations require a reward for the vigorous (and risky) pursuit of cost efficiency. Setting the benchmark to that of the highest performer dulls those incentives since no one would have an incentive to be the leader. However, setting the benchmark at the lower end of performance takes pressure off inefficient businesses. The decision about where to set the line is difficult and involves judgment.

(c) Quality must not be overlooked. A business subject to incentive regulation may appear to be performing efficiently in cost terms, but may lower its quality. This is why, regardless of the regime used to set revenue allowances, complementary regulation or incentive schemes specifically related to reliability, are also necessary. This is much more difficult in transmission where there are few good output measures of likely future reliability performance.

(d) Different reporting systems produce measurement errors.

(e) Any comparisons between businesses must take into account differences in their operational circumstances (such as topography, customer density, and differences between jurisdictions about which assets lie within transmission or distribution networks) and policy constraints (such as higher or differently defined reliability standards or statutory requirements for non-commercial goals for state-owned corporations). Much of the international academic literature on benchmarking uses too few variables to draw strong inferences about the efficiency of specific firms.

(f) There are only 13 distribution businesses, five regional transmission businesses and three separate DC interconnectors in Australia, which reduces the capacity for elaborate models that take into account (e). It also means that the performance bar might be set quite low if the highest performing Australian business were still quite inefficient. International benchmarking might assist, but has to be interpreted carefully given that adjusting for the differences noted in (d) and (e) may increase the number of variables at a higher rate than the additional number of businesses used in benchmarking.

Such difficulties are less severe if the purpose of benchmarking is to identify broad efficiency concerns about network businesses. However, in setting regulatory allowances, badly configured benchmarks could lead to under-remuneration of businesses, with risks for efficient investments and business solvency.

Nevertheless, benchmarking may usefully test specific features of a network business's proposal. Operating expenses, such as the costs of vegetation clearance around poles and wires, are more generally amenable to benchmarking than capital expenditure. Such specific benchmarking may be reasonably reliable because there are fewer confounding variables. It may also be possible to expand the number of comparisons by analysing performance outcomes from many regions of any given business. The AER has made some use of such benchmarking, as have network businesses for commercial purposes, underlining that it is sufficiently robust to be useful.

If its rigour and accuracy improves, aggregate benchmarking could also encourage early settlement in determinations, short-circuiting the current costly processes. Depending on the divergence between benchmarking and the business proposal, the AER could immediately accept a proposal as reasonable, or if the proposal were in the 'ballpark', commence negotiations with the network business, with the involvement of consumers. The AER could also request further information (a 'please explain' notice) to assist the early resolution of an agreement. Failing a quick resolution, the AER would adopt the current forensic and protracted processes. The risks and costs of those processes would encourage parties to seek negotiated settlements.

A Rule change would be required to allow the AER to use benchmarking (or any other evidence at its discretion) on a standalone basis, where it led to an early and *mutually agreed* outcome between the business, the regulator and consumers.

Processes and resources for benchmarking

A major study ranked Australia as a relatively unsophisticated user of benchmarking in electricity networks. Recognising this, the AER has recently reviewed the use and methods of benchmarking by other energy regulators, and is collecting data that would allow it to undertake more elaborate benchmarking. However, the AER should adopt further measures to ensure the successful use and evolution of benchmarking, including:

- the development of publicly available databases and full transparency in the processes and methods the AER uses in its benchmarking. (The standard of reporting of benchmarking and testing of its rigour and robustness would need to be high before the results could play a major role in revenue determinations.)
- the development and retention of internal expertise, strategies that maximise learning and greater international collaboration with other regulators and benchmarking agencies

- peer review of its benchmarking practices ('benchmarking of benchmarking')
- appropriate consultation with stakeholders about the required data and appropriate methods and regular checking to ensure that the benefits of its benchmarking practices exceed the compliance and resource burdens.
- effective communication of the results of benchmarking to its diverse audiences, and in particular to consumer groups, which may use the information to place greater pressure for improved performance by network businesses.

Such initiatives may eventually allow benchmarking to serve a greater role in making regulatory determinations. If benchmark methods become sufficiently robust, the current onus of proof might be switched, with a business having to explain why its alternative proposal would be reasonable. Setting the benchmark target at a slightly less demanding level that that of a fully efficient firm could provide some protection against regulatory error.

Interconnectors

In contrast to concerns about over-investment in each region's own network, some stakeholders argue that there has been underinvestment in interconnectors, citing the presence of interconnector congestion as an indicator of this. They claim that underinvestment has led to insufficient trade in energy across borders and the use of market power by some generators, and acted as a barrier to the wider use of low-carbon emitting generators (particularly wind).

However, there are several major flaws in these claims:

- Congestion is not inherently bad. Just as in roads, some congestion is efficient because the costs of lowering congestion can exceed the benefits. The current evidence suggests that interconnector capacity is close to its optimal level. For example, cost–benefit analyses of interconnector upgrades or new interconnectors suggest that these are only economically efficient in the future.
- The problems attributed to apparent underinvestment in interconnectors — such as the exercise of market power by some generators — are often the consequence of other aspects of the network and the regulatory system. Simply increasing interconnector investment would often not resolve these problems, or would not be the most efficient way of doing so.

The Rules may sometimes affect the bidding behaviour of generators in perverse ways. This can undermine the purpose of interconnectors by impeding the efficient use of excess capacity (quite the opposite of a problem with congestion). Moreover, the regulatory regime for transmission (of which interconnectors are a part) should

be future looking. Accordingly, while existing interconnection infrastructure may be satisfactory, the current system may not deliver efficient future investment.

The reasons for this are highly technical, but the main factor undermining the efficient use of interconnectors is the strategic behaviour of generators, which is encouraged by the design of the spot market in the NEM, the physical configuration of both transmission and generation in the NEM and the way that transmission services are priced.

When transmission constraints bind, it may be necessary to dispatch higher cost generators ahead of more efficient ones to meet demand. But this can also be the result of, or be exacerbated by, strategic behaviour by generators (so-called 'disorderly' bidding) located behind a constrained transmission line. They can also prevent the dispatch of efficient generators in another state and thereby reduce traffic on an interconnector, sometimes precisely when maximising flows would be helpful to meet peak demand in another jurisdiction. Indeed, in certain bizarre instances, generator bidding behaviour may result in 'counterflows', in which the pattern of trade violates the usual assumptions of comparative advantage. Generators with higher costs send power to a state with lower-cost generators. Disorderly bidding can be a highly profitable strategy for generators.

In the short-run, this conduct mainly results in income flows between parties, but not inefficiency. However, over the longer run, it has several perverse outcomes:

- generators face inefficient signals about where to locate
- older higher-cost generators may not be decommissioned early enough
- the capacity of inter-regional contracting across interconnectors to provide insurance through hedging instruments is undermined, forcing parties to use more costly hedging, or to avoid inter-regional trading altogether
- the signals for the efficient investment in interconnectors are distorted, and with that, network planning across the NEM.

The Commission agrees with the option proposed by the AEMC in its transmission frameworks review. Disorderly incentives can be removed by providing for 'optional firm access'. Under this arrangement, generators can pay for privileged ('firm') access, or if choosing open access, risk paying compensation if they are dispatched out of order. This would achieve short-term gains and provide long-run locational signals.

Quite apart from reforms to transmission pricing, the Commission's preferred NEM-wide planning approach (as discussed earlier) is likely to overcome biases against interconnectors arising from a tendency to favour intra-regional

transmission options. Despite some concerns, the framework for the RIT-T (Regulatory Investment Test for Transmission) for any major new transmission projects is generally sound. Nonetheless, requiring that an independent planner undertake the test in close consultation with the transmission business is likely to ensure that all relevant options (including inter-jurisdictional options) have been considered.

Implementation and outcomes

In considering benchmarking and interconnectors, the Commission has necessarily had to examine how the whole NEM functions, but with a particular focus on networks. It has proposed a suite of coordinated reforms (table 1) that aim to take account of the many inter-relationships in what amounts to a complex economic 'machine'. However, such reforms require careful implementation (table 2).

Over time, the fundamental objective of the NEM — the need for efficient investment in, and operation of, networks in the long-term interests of consumers — has lost its justifiable pre-eminence. The current NEM is 'off-course' to deliver this objective. This has been apparent in the merits review process, parochialism, too much focus on the network businesses (exemplified by transmission planning and reliability issues), the gradualism of retail reform, continued government ownership of network businesses, and above all, the muted role of consumers themselves in the processes.

Major stakeholders, particularly investors in long-lived network assets, are understandably nervous about any changes to the rules and regulatory environment that might adversely affect their investments. Meeting the *long-run* interests of consumers requires that investors are confident that the regulatory regime will deliver adequate returns on their investment. Some may argue that the Commission's suite of recommendations represent an unacceptable rate of change and risk to investor confidence. To this, the simple but fundamental point is that the recommendations made by this inquiry do not represent any change to the 'goal posts' of the NEM — with the fundamental uncertainty that would entail for consumers and network businesses. Rather, the recommendations are designed to re-orient the framework to better achieve its original objective.

There have been some legitimate reasons for price increases over the last few years, but the system as a whole is inefficient, and price pressures could be reduced substantially over the longer term if a coordinated set of reforms were introduced. Consumers have much to gain from the proposed reforms.

How can the Commission's review fit into the reform agenda?

The existing governance arrangements for the NEM ensure that any consequential Rule changes only occur after in-depth analysis and transparent consultation by an independent body — the AEMC. The South Australian Minister — with agreement by other jurisdictions in the Standing Council on Energy and Resources — has previously had a (limited) capacity to make Rule changes, but that capacity has lapsed.

One Achilles' heel of these processes is that a parallel review — such as this inquiry or the recent evaluation of the limited merits review regime — that uses similar transparent processes and analytic methods, does not appear to remove the need for formal Rule change requests and further AEMC reviews. The implication is that reviews lead to reviews, which delays reforms and adds burdens to stakeholders.

The burdens posed by inertia and compliance costs could be resolved by amending the National Electricity Law so that the Rules can be changed if the reform proposal is underpinned by an independent and consultative review undertaken by an appropriate agency, and whose recommendations are agreed by the Standing Council.

The Commission recommends that, subject to endorsement by the Standing Council, it should give the:

- AEMC the power to fast-track Rule changes based on the outcomes of such reviews (extending its current capacity to accelerate reviews for minor matters), and
- South Australian Minister a broad 'one shot' power to make Rules when a comprehensive review has occurred.

Table 1 **A summary of the Commission's main proposals**

Current problem	*Proposed response*	*Main benefits from reform*
A focus on consumers The National Electricity Objective (the long-term interests of consumers) has lost its pre-eminence in regulatory decisions.	A new consumer body, with the expertise and funding to be an effective participant in the regulatory process should be created. (The limited merits review process should also be reformed)	Customers would have more power in the regulatory process, keeping the NEO in sight and preventing undue focus on technical, financial and legalistic details.
Demand management Some 25 per cent of (expensive) system investment is required just to meet 40 hours of critical peak demand each year.	A coordinated suite of reforms should be introduced over time, including consumer consultation, removal of retail price regulation, and the phased introduction of smart meters, accompanied by time-based pricing for critical peak periods. Direct load control options — complementing or substituting for time-based pricing — would also play a role.	System use and investment would be better aligned, reducing the amount of expenditure required just to meet peak periods. The Commission estimates net annual savings of $100–$250 per household (after smart meters are installed).
Reliability Reliability is critical to electricity networks, but the current standards are not set efficiently, and often bear little relationship to the value to customers.	Reliability decisions should be based on customers' valuations, not prescriptive standards. • For distribution, a new national reliability framework should be introduced, and incentive schemes reformed to reflect customer preferences • For transmission, reliability standards should be set on a NEM-wide basis, and involve a single transmission planner (which would also benefit ***interconnectors***).	• Distribution: in NSW alone, $1.1 billion of network capital expenditure could be deferred until the next five year regulatory period. The actual, NEM-wide, savings are likely to be larger. • Transmission: a new reliability framework could defer around $2 to 3 billion of investment across the NEM, over the next five year regulatory period.
Network ownership State-owned network businesses and their owners have conflicting objectives, which can frustrate the effectiveness of incentive regulation. There is no evidence that state-owned businesses outperform private ones, and some evidence to the contrary.	State-owned network businesses should be privatised. If not, governance should be improved, and non-commercial objectives and policies should be removed.	In the first instance, the efficiency of network businesses can be expected to improve, reducing costs to customers. ***Incentive regulation*** would also become more effective, reinforcing efficiency improvements.
Incentive regulation The current incentive regulation regime encourages businesses, especially state-owned ones, to build too much.	Some obvious flaws should be eliminated, including: • ensuring the allowed rate of return on regulated assets is not excessive • ex post review of capital spending, when businesses overspend • no requirement for the AER to consider every detailed aspect of proposals.	Incentive regulation would be more effective at encouraging efficient investment.

Table 1 **continued**

Current problem	*Proposed response*	*Main benefits from reform*
Governance of regulators There appears to be little confidence amongst stakeholders that the AER has sufficient resourcing, expertise and capacity to fulfil current obligations. Future reforms would only add to these obligations.	In the first instance, there should be a review of the AER's resources and capacity. The AER should be given more control over its budget, and be more accountable for how it manages resources and improves its performance. A more far-reaching option could be to establish the AER as a separate, independent entity. This raises complex issues, and the Commission is still assessing its merits.	The AER would be better able to perform its (current and future) role, improving the effectiveness of ***incentive regulation.***
Benchmarking Information asymmetries make it difficult for the regulator to accurately assess the efficiency of businesses' proposals	At this stage, benchmarking is too unreliable to be used to set regulated revenue allowances, but could better inform the regulator's decisions. In the future (after the rigour and accuracy of benchmarking improves), reforms could be made to underpin negotiations for 'early settlements' with businesses, and potentially to base allowances on benchmarking.	Better information could improve the accuracy and effectiveness of incentive regulation, lowering prices to consumers. Additionally, in the future, lengthy regulatory determinations could be avoided, reducing compliance costs.
Interconnectors There is no evidence of insufficient physical capacity of interconnectors. Indeed, they are sometimes underutilised due to perverse incentives in the structure of the wholesale market. Underutilisation may often coincide with periods of peak demand when the interconnectors would be most valuable.	There should be reforms to the wholesale market to influence generator bidding behaviour, and change the way they pay for access to the transmission network. The 'optional firm access' package currently being considered by the AEMC would implement such reforms. In the long-term, 'nodal pricing' should be introduced with a system of financial transmission rights (pending an implementation review).	Generator bidding behaviour (and locational choices) would be more closely aligned to efficient levels. In the long term, this would allow better flows along interconnectors, improve certainty in (electricity) financial markets and improve interconnector planning. (Introduction of 'optional firm access' would lead some transmission investments becoming market-driven, improving the alignment of investment expenditure with user benefits.)

Table 2 **The timing of reform**

Timing	*Measure (and corresponding draft recommendations)*
Already underway	• changes to incentive regulation, including ex-post evaluation of overspends to be incorporated in the Australian Energy Market Commission's rule change, completed by November 2012. (*r. 5.1–5.6)*
Initiate now	• initiate changes to expedite the Rule change process where policies have been subject to independent and appropriately undertaken reviews *(r. 21.4)* • phase out retail price regulation, subject to adequate impending competition *(r. 12.3)* • state and territory governments to introduce feed-in tariffs that reflect the value of providing power to the grid at peak and non-peak time *(r. 13.1)* • the Australian Energy Regulator to: – at this stage, use aggregate benchmarking to inform (but not use as the exclusive basis for) determinations *(r. 8.1, 8.5)* – begin (ongoing) development of detailed benchmarking performance and control variables, with periodic review for relevance and compliance costs *(r. 8.2, 8.3, 8.6, 8.8, 8.9)*. Benchmarking results and data to be public *(r. 8.7, 8.11)* – increase the innovation allowance component of the Demand Management Embedded Generation Connection Incentive Scheme for distributors (*r. 12.2)* – be given greater control over, and accountability for its financial and staff resources. (r. 21.2) – have its resourcing and capacity subject to review *(r. 21.1).* • the Australian Energy Market Operator, network businesses and other experts, to review the technical aspects of probabilistic planning (r. 15.5) • transmission businesses that do not already use them should transition to dynamic capacity ratings *(r. 15.10)*
Mid 2013	• the Australian Energy Market Operator to commission the Australian Bureau of Statistics to undertake surveys for the value of customer reliability *(r. 14.1)* • the Standing Council on Energy and Resources to develop common criteria for assistance to vulnerable consumers *(r. 11.6)*
By end 2013	• the Australian Energy Market Operator to take on the role of a decision-making national transmission planner, and implement probabilistic planning for the entire NEM transmission network *(r. 15.2)* • state and territory governments to create a single set of licence conditions for network businesses, expressed in the National Electricity Rules and administered by the Australian Energy Regulator *(r. 11.2)* • the Standing Council on Energy and Resources to remove jurisdiction-specific distribution reliability requirements. Distribution reliability settings to be contained in the Service Target Performance Incentive Scheme with the reliability settings driven by consumer preferences. *(r. 16.1)*

(continued on next page)

Timing	*Measure*
By end 2013 (continued)	• a new, single, consumer representative body with expertise in economic regulation to be established and adequately funded *(r. 21.3)* • the Australian Energy Regulator to: – complete a review of the Service Target Performance Incentive Scheme for transmission to ensure consistency with the new reliability framework *(r. 15.9)* – amend the Service Target Performance Incentive Scheme for distribution *(r. 16.2)* – assess the costs and benefits of rolling out smart meters on a region-by-region basis, including consumer consultation *(r. 10.1)* • (within six months of the conclusion of a positive assessment by the Australian Energy Regulator) distribution businesses to submit costings and agreed timelines for rollout of smart meters *(r. 10.1)* • (once meters are installed, and retail price regulation removed) mandatory time-based network charges to be implemented *(r. 10.1, 11.4, 11.2)*
2013–2016	• the Australian Energy Regulator to use weighted average price (not revenue) caps for regulation of distribution businesses *(r. 12.1)* • the National Electricity Rules to be amended to ensure that network tariffs efficiently recover the costs of peak capacity, with particular reference to long run marginal costs *(r. 11.3)* • state and territory governments to privatise network businesses *(r. 7.1)*, after announcing reliability framework
Second half of 2014	• the Australian Energy Market Commission's 'optional firm access' package to be implemented. It should – operate for at least 10 years – be monitored by the Australian Energy Market Operator for effects on network planning and, in concert with the Australian Energy Regulator, changes in observed patterns of generator bidding behaviour *(r. 18.1)* • the Australian Energy Regulator to oversight the public reporting process of the Australian Energy Market Operator's planning role *(r. 15.4)*
By 2018	• subsidies that stimulate inefficient investment in and positioning of rooftop photovoltaic units should have been fully phased out *(r. 13.1),* but existing contracts should be honoured
2019	• the Australian Energy Regulator to: – if benchmarking is robust enough, it should be the basis for (quicker and less elaborate) regulatory determinations. The onus of proof would be on a network business' proposal to demonstrate its cost estimates were preferable *(r. 8.5)* – where the divergence between estimates is narrow, have discretion to reach a mutually acceptable negotiated settlement with a network business, with the involvement of the consumer representative group *(r. 8.4)*
2025	• barring the identification of any significant, insurmountable barriers in a pre-implementation cost-benefit analysis, nodal pricing (including financial transmission rights) to be implemented *(r. 18.2)*

Draft Recommendations and findings

Chapter 5 Regulatory incentives

DRAFT RECOMMENDATION 5.1

The Australian Energy Regulator should develop an efficiency benefit sharing scheme to apply to capital expenditure that provides consistent incentives to reduce capital expenditure, both over time and when compared with operating expenditure.

DRAFT RECOMMENDATION 5.2

The National Electricity Rules should specify the interdependent nature of the parameters used to estimate the weighted average cost of capital, and specify that any merits review must also consider the relevant rule in that light.

DRAFT RECOMMENDATION 5.3

Estimates of the debt risk premium and risk free rate used in the calculation of the weighted average cost of capital should be calculated using long-term trailing averages.

DRAFT RECOMMENDATION 5.4

Where, within a given regulatory period, a network business spends materially more capital than that allowed for in the Australian Energy Regulator's final ex ante regulatory determination, then its entire capital expenditure should be subject to an ex post prudency test:

- ***Only spending that is deemed efficient and prudent, given the information available to the network business at the time, should be included in the Regulatory Asset Base at the end of the period, subject to the condition that:***
  - ***the maximum disallowable expenditure is no more than the difference between the ex ante forecast and realised expenditure***
- ***If a network businesses is aware that it is going to exceed pre-approved spending levels, it should be able to apply for pre-approval to avoid the ex post assessment.***

The prudency test should not apply to cost pass throughs and contingent projects permitted under chapters 6 and 6A of the National Electricity Rules.

DRAFT RECOMMENDATION 5.5

The National Electricity Rules should be clarified to indicate that the Australian Energy Regulator is only required to test the reasonableness of the overall expenditure proposal. The Regulator should only be obliged to consider the reasonableness of a specific expenditure item if it could materially affect the judgment of the reasonableness of the total expenditure forecast.

DRAFT RECOMMENDATION 5.6

In cases where the Australian Energy Regulator considers that the National Electricity Rules constrain its capacity to make appropriate revenue determinations, it should publish its preferred estimate along with the final determination, explaining the differences. In any subsequent merits review of its determination, the Australian Energy Regulator should ensure that the reasons behind its preferred estimate are clearly communicated to the merits review body.

Chapter 7 Ownership

DRAFT RECOMMENDATION 7.1

State and territory governments should privatise their state-owned network businesses.

DRAFT RECOMMENDATION 7.2

If state and territory governments do not implement draft recommendation 7.1, then they should promote more efficient outcomes for their state-owned network businesses by ensuring that:

- ***directors are appointed on merit, following a transparent selection process***
- ***ministerial directions are publicly disclosed at the time they are made and disclosed in the annual report***
- ***directors and officers are subject to the obligations under the Corporations Act***
- ***governments review objectives currently given to network businesses and:***
  - ***remove those that would be more appropriately allocated to other agencies***

- *remove those that are non–commercial and make it clear that the board is expected to deliver a dividend payout and rate of return on the equity invested in the network business that would be considered acceptable by an independent investor*
- *where conflicting objectives remain, provide publicly transparent guidance on how to prioritise them.*

Chapter 8 Using benchmarking

DRAFT RECOMMENDATION 8.1

The Australian Energy Regulator should regularly undertake aggregate benchmarking of the performance of network businesses, including of their:

- ***multifactor productivity — the output of services for given inputs***
- ***separate productivity of capital, labour and intermediate inputs.***

The results should control, to the best extent available, for any significant variations in the operating environments of the businesses, including customer density, line type and length, reliability requirements, and the capital vintage of relevant assets.

DRAFT RECOMMENDATION 8.2

Subject to compliance and other costs (draft recommendation 8.12), the Australian Energy Regulator should accompany aggregate analysis with detailed benchmarking of particular aspects of the performance of the businesses, including:

- ***the rate of investment relative to the age-weighted capital stock by asset class***
- ***the efficiency of major maintenance activities***
- ***the adoption rate of best-practice commercial processes and equipment, including the use of customer panels and surveys, outsourcing, demand management, information technologies, financial controls, procurement practices, occupational safety, and project management.***

In determining relevant benchmarking performance and control variables, the Australian Energy Regulator should consult with:

- ***network businesses, generators, retailers and network equipment suppliers***
- ***customer representatives***
- ***relevant experts within Australia and internationally.***

DRAFT RECOMMENDATION 8.3

The Australian Energy Regulator should periodically assess the comparative performance of network business units within particular sub-regions of the National Electricity Market, where:

- ***those sub-regions share similar physical operating environments***
- ***the costs and informational requirements of doing this are not too great (draft recommendation 8.12).***

The comparisons should relate to business units within a particular business, as well as comparable business units in different businesses.

The Australian Energy Regulator should place most emphasis on comparisons of the efficiency of distribution networks in different metropolitan areas.

DRAFT RECOMMENDATION 8.4

The Rules should be changed to allow the Regulator to have the discretion to initiate a three-way negotiation of a mutually acceptable settlement, involving itself, the business, and a representative and qualified customer group similar, or identical, to that identified in draft recommendation 21.3.

- ***Negotiation would only be triggered if the Australian Energy Regulator judged that the divergence between aggregate benchmarking estimates of forecast spending and the business's proposal were sufficiently narrow.***
- ***Where an arrangement was successfully negotiated using this process, the Australian Energy Regulator should not be obliged to go through the current formal draft/final determination processes.***

DRAFT RECOMMENDATION 8.5

In any of the next rounds of regulatory determinations, the Australian Energy Regulator should not use aggregate benchmarking as the exclusive basis for making a determination. Instead, the Australian Energy Regulator should use such aggregate benchmarking results as a diagnostic tool in responding to business cost forecasts.

However, if the processes proposed in draft recommendations 8.9 to 8.11 led to sufficiently robust benchmarking, then:

- ***a business would continue to make a detailed cost proposal, but if the overall proposal were divergent from the regulator's benchmarking estimate, the onus of proof would be for a network business to provide quantitative evidence demonstrating why its cost forecast was preferable in meeting the National Electricity Objective***
- ***the Australian Energy Regulator's efficiency threshold applied to firms should be set close to, but below, the level of the most efficient firm.***

DRAFT RECOMMENDATION 8.6

The Australian Energy Regulator should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.

DRAFT RECOMMENDATION 8.7

The Australian Energy Regulator should make all benchmarking input data publicly available (recognising that the businesses being benchmarked are regulated monopolies) except where the data can be demonstrated to be genuinely commercial-in-confidence.

Where the latter holds, the Australian Energy Regulator should still make the full datasets available to:

- ***independent researchers who are using the results for non-commercial purposes***
- ***the consumer group involved in any negotiations described under draft recommendation 8.4***
  - ***but subject to statutory requirements for non-disclosure of information predetermined as commercially-in-confidence, drawing on existing models for data protection.***

DRAFT RECOMMENDATION 8.8

When making its revenue allowance determinations, the Australian Energy Regulator should make judgments about capital expenditure forecasts that take account of any discrepancy between the Australian Energy Market Operator's top-down peak and average demand forecasts and the aggregate of distribution businesses' bottoms-up peak and average demand forecasts.

The Australian Energy Regulator should use benchmarking of the discrepancies between previous expenditure forecasts and actual outcomes by different parties to inform that process.

DRAFT RECOMMENDATION 8.9

The Australian Energy Regulator should collaborate with other leading regulatory agencies, academic experts and global commercial benchmarking specialists to enable robust meta-analysis of electricity network benchmarking results from individual country (and where credible, multi-country) studies. The collaboration should include cooperation in developing:

- ***the most meaningful measures of performance***
- ***consistent data collection***
- ***consistent reporting of results***
- ***best-practice analytic frameworks.***

DRAFT RECOMMENDATION 8.10

The Australian Energy Regulator should submit its major benchmarking analyses of electricity networks for independent expert peer review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to gauge the degree of uncertainty in the results.

DRAFT RECOMMENDATION 8.11

The Australian Energy Regulator should make its benchmarking results publicly available, with:

- ***accessible reporting of the results to inform consumer groups, network businesses, and others***
- ***disclosure of the importance of factors outside the control of businesses, but that may be controllable by governments***
- ***publication of the modelling strategy used to produce the results***
- ***the sensitivity of the results to changes in key assumptions***
- ***the performance of any statistical models against accepted scientific standards, including confidence intervals, parameter stability, and specification testing.***

DRAFT RECOMMENDATION 8.12

The Australian Energy Regulator should periodically examine its detailed benchmarking methodologies and processes to assess their compliance costs for businesses and the costs for the Australian Energy Regulator. It should compare these costs with the likely benefits when determining the appropriate frequency and type of detailed benchmarking. In undertaking such assessments, the Australian Energy Regulator should consult closely with network businesses.

The Australian Energy Regulator should make all such assessments publicly available.

The overall costs of benchmarking should be subject to independent review after five years.

Chapter 10 Demand management technologies

DRAFT RECOMMENDATION 10.1

Distribution businesses should implement the roll-out of advanced metering infrastructure — so called smart meters — on a region-by-region basis within their network.

- ***Before any roll-out, the Australian Energy Regulator, drawing on the proposal and supporting evidence from the distribution business, should assess the net present value of costs and benefits, and be required to consider demand management options that do not rely on smart meters.***
- ***When the Australian Energy Regulator determines the optimal start date of the roll-out, the relevant distributor must submit a costing to the Regulator for approval and agree to an appropriate timeline for implementation.***
- ***Mandatory time-based network charges to retailers (draft recommendation 11.3) should be implemented once smart meters are installed, appropriate customer consultation and education has taken place, and retail price regulation is removed (draft recommendation 12.3).***

Chapter 11 Time-based pricing

DRAFT RECOMMENDATION 11.1

The Standing Council on Energy and Resources should be tasked with overseeing the progressive implementation of cost-reflective, time-based pricing for electricity distribution network services, predicated on the long run marginal costs of meeting peak demand. Amongst other things, the Council should:

- ***following consultation with key stakeholders, set timelines for the various steps in the development and implementation process, having regard to:***
  - ***the Commission's specific proposals in relation to this process (draft recommendations 11.2 to 11.7)***
  - ***progress in making necessary changes elsewhere in the system***
- ***monitor compliance with those timelines***
- ***address any areas where greater engagement between key stakeholders (distribution businesses, retailers, state and territory governments, the Australian Energy Regulator and customer representatives) would assist the expeditious implementation of the new pricing regime***
- ***if and as necessary, take specific steps to address implementation delays.***

DRAFT RECOMMENDATION 11.2

The Standing Council on Energy and Resources should initiate a process to establish a uniform set of licence conditions for all transmission and distribution network businesses in the National Electricity Market. The Council should task the Australian Energy Market Commission to undertake a framework review to assist that process.

The development of a uniform set of licence conditions should have regard to the Commission's proposed changes to the reliability framework (draft recommendations 15.1 and 16.1) and should not in any way conflict with, or impede, the implementation of that framework.

The uniform licence conditions should be included in the National Electricity Rules and replace the current state and territory licence conditions.

It may not be immediately feasible to develop standardised provisions governing technical standards and safety, though these should ultimately be encompassed in the national set of licence conditions.

The justification for any jurisdiction-specific conditions included in the new licensing regime should be clearly and cogently spelt out in the supporting framework review.

Before incorporation into national licence conditions, preparatory work would be needed to develop a common approach to the identification of customers in need of special support to meet their electricity bills or pay for smart meters (draft recommendation 11.6), but:

- ***pending agreement on appropriate national criteria and approaches to funding, each state and territory government should continue to be responsible for targeted financial support to address affordability.***

The Australian Energy Regulator should be responsible for ensuring compliance with the new conditions and would have the authority to:

- ***issue and retract licences***
- ***seek advice from relevant agencies on any technical matters relating to compliance assessment.***

Provision could also be made in the Rules for the Australian Energy Regulator to delegate responsibility for assessing compliance with particular licence conditions to a relevant state-level regulator.

DRAFT RECOMMENDATION 11.3

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced to reasonably allow for a tightening of relevant clauses in the National Electricity Rules:

- ***clause 6.18.5(b)(1) should be amended so as to ensure that time-based tariffs are determined by (rather than 'take into account') a reasonable estimate of the long run marginal cost for the service concerned***
- ***clause 6.18.3(d)(1) should be amended so as:***
  - ***to ensure that the grouping of customers for the purposes of setting time-based tariffs is based on economic efficiency (rather than 'having regard to' it)***
  - ***to make it explicit that significant differences in the long run marginal cost of meeting peak demand between locations and across customer groups should be reflected in network pricing structures.***

DRAFT RECOMMENDATION 11.4

When the process of implementing cost-reflective, time-based prices for distribution network services is suitably advanced, the requirements governing assessments by the Australian Energy Regulator of pricing proposals by distribution network service providers should be amended such that the regulator:

- ***can only approve a distribution business's peak demand forecasts if they include reasonable forward estimates of the likely demand response to time-based pricing***
- ***subject to the above condition, must approve any reasonable estimate by a distribution business of the long run marginal costs of meeting peak demand.***

To support these changes, the Australian Energy Regulator should develop a capacity to model demand responsiveness to time-based pricing.

DRAFT RECOMMENDATION 11.5

Clause 6.2.8(a)(3) of the National Electricity Rules should be amended to:

- ***require the Australian Energy Regulator to publish guidelines on the methodology or methodologies that are appropriate for estimating the long-run marginal costs of meeting peak demand, and the factors that should be encompassed in those estimates***
- ***give the Australian Energy Regulator the authority to publish binding guidelines about efficient, time-based tariff structures, including definitions of 'peak' pricing events.***

These guidelines should be developed in consultation with the relevant stakeholders and should be improved over time as the implementation of time-based pricing progresses.

DRAFT RECOMMENDATION 11.6

The implementation of cost-reflective, time-based pricing for distribution network services should be accompanied by assistance for vulnerable consumers, which should target those who:

- ***are potentially exposed to large price increases and who do not have reasonable opportunities to switch their demand to non-peak periods***
- ***will potentially face significant difficulty in meeting the charges used to recover the costs of smart meters.***

The Standing Council on Energy and Resources should develop common criteria for identifying who should receive such assistance, and when it should be delivered through electricity specific mechanisms rather than through the Australian Government's tax and transfer system. These criteria should be based on the outcomes of a review commissioned by the Council of Australian Governments of concessions for utility services across all levels of government (consistent with recommendation 8.1 of the Productivity Commission's Urban Water Sector Inquiry report).

These criteria, and a commitment to transparent funding of the electricity sector-specific support should then be reflected in the new National Electricity Market-wide licence conditions for network businesses (draft recommendation 11.2).

DRAFT RECOMMENDATION 11.7

The Australian Energy Regulator should require:

- ***distribution network businesses to demonstrate that they have actively engaged with retailers very early in the development of new time-based pricing structures, including on ways to incorporate those charges in retail prices to clearly signal to customers the costs of meeting peak network demand***
- ***distributors and retailers to demonstrate that they have engaged with, and educated, customers prior to the introduction of smart meters, and again prior to the introduction of new time-based customer tariffs.***
  - ***Such engagement should occur sufficiently early to ensure that customers have the knowledge and time to respond appropriately to time-based pricing (including of the various means to manage their peak demand); are aware of the implications for their electricity bills; understand the way in which advance warning of critical peak pricing events will be communicated; and are aware of the support mechanisms in the event that the new pricing regime creates financial difficulties for them.***

Chapter 12 Complementary reforms to support demand management

DRAFT RECOMMENDATION 12.1

Coinciding with the gradual roll-out of smart meters to allow more cost-reflective network pricing, revenues from all distribution network 'standard control services' should be subject to regulated weighted average price (not revenue) caps. This should not apply to transmission businesses, which, given the complexities and lower net-benefits, should continue to be subject to revenue caps.

DRAFT RECOMMENDATION 12.2

The Australian Energy Regulator should review the operation of, and the incentives provided by, the Demand Management and Embedded Generation Connection Incentive Scheme. In doing so, the Australian Energy Regulator should ensure that distribution companies' incentives are appropriately aligned with the objective of achieving efficient demand management. The innovation allowance component of this scheme should also be increased.

DRAFT RECOMMENDATION 12.3

Where retail price regulation exists, the Australian Energy Market Commission should review the market for effective competition.

- ***In jurisdictions where the Australian Energy Market Commission advises that retail price regulation should be removed, the relevant state or territory government should remove retail price regulation as soon as practicable.***
- ***Where the Australian Energy Market Commission advises that there is strong evidence that competitive pressures would be weak with the removal of the regulation, and could not be addressed by consumer awareness measures:***
  - ***it should suggest any structural reforms that would be necessary to develop workable competition. These reforms should be promptly progressed by the relevant jurisdictions, and retail price regulations should be removed by no later than 2015.***

Chapter 13 Distributed generation

DRAFT RECOMMENDATION 13.1

Governments should, as soon as practicable, discontinue subsidies for rooftop photovoltaic units and other forms of distributed generation delivered via feed-in tariffs, and the small-scale component of the Renewable Energy Target scheme.

State and territory governments should change the way small-scale distributed generators are reimbursed for exporting power into the grid. This would involve:

- ***feed-in tariffs that approximate the wholesale price of electricity at times of peak and non-peak demand***
- ***arrangements that provide for direct payments from distribution businesses to distributed generation providers, which reflect the network value of their distributed generation capacity and output.***

To provide a transition to the new arrangements, current feed-in tariff schemes should continue for existing customers until the end of their contract period or until those schemes expire (whichever is earlier), but be closed to new entrants one year from governments' formal acceptance of this recommendation. Prior to that date, state and territory governments should develop replacement feed-in schemes with tariffs that approximate the wholesale price of electricity.

Chapter 14 Reliability frameworks

DRAFT FINDING 14.1

Efficient levels of reliability are based on balancing the benefits to customers of fewer interruptions with the costs to network businesses of building, maintaining and operating reliable networks. Identifying the point at which the costs to network businesses of further increments in reliability exceed the additional benefits for customers should be the first step in regulating reliability.

DRAFT FINDING 14.2

Current estimates of the value that customers place on reliability are based on inadequate sampling, data and methodology and need to be updated regularly.

DRAFT RECOMMENDATION 14.1

The Australian Energy Market Operator should commission and pay the Australian Bureau of Statistics to undertake regular, detailed, disaggregated surveys based on best practice methodologies to reveal the value of reliability for different categories of customers, with the methodologies and results made public.

The Australian Energy Market Operator should commission suitably qualified experts to consider and measure the costs of interruptions not likely to be captured in the Australian Bureau of Statistics surveys. This should include the costs associated with citywide disruptions, including to telecommunications, water services and public transport, and the resulting loss of international reputation from lower reliability. The Australian Energy Market Operator should use these measures to supplement the results of the surveys.

Chapter 15 Transmission reliability

DRAFT RECOMMENDATION 15.1

The Standing Council on Energy and Resources should, in consultation with the Australian Energy Market Operator and the Australian Energy Market Commission, develop a National Electricity Market-wide reliability framework in which reliability settings would be determined by customer preferences.

This framework should replace all jurisdiction-specific reliability settings.

DRAFT RECOMMENDATION 15.2

Drawing on the current Victorian experiences, the Australian Energy Market Operator should carry out transmission planning for all transmission networks in the National Electricity Market. The Operator should:

- ***use Values of Customer Reliability (as obtained through draft recommendation 14.1)***
- ***use best practice probabilistic processes in its cost-benefit analysis of network and non-network options to address reliability issues and/or constraints***
- ***describe its full cost-benefit analysis as part of its process for the Regulatory Investment Test for Transmission***
- ***make public all methodologies, parameters, data and other inputs used in the analysis***
- ***work closely with each of the transmission companies concerned to make sure that their experience and input is fully understood and where mutually agreed, appropriately incorporated into the analysis***
- ***use its best estimate of peak demand forecasts, having sought input from all relevant stakeholders***
- ***ensure that planning decisions are consistent with National Electricity Market-wide efficiency objectives***
- ***not carry out the 'procurer' role currently done in Victoria until it can be demonstrated that the benefits of such an approach exceed the costs in the Australian National Electricity Market environment.***

DRAFT RECOMMENDATION 15.3

In consultation with the transmission network businesses, the Australian Energy Market Operator should specify the details of the network or non-network solution to an identified constraint.

If the cost of the solution is less than an appropriate threshold, then:

- ***the Australian Energy Market Operator and the network business should negotiate and agree on the required expenditure. If there is no agreement, the Australian Energy Regulator should determine the allowable spending.***

If the costs exceed the above threshold, then:

- ***the transmission business should submit detailed and final costings to the Australian Energy Regulator***
- ***with advice from the Australian Energy Market Operator, the Australian Energy Regulator should determine the allowable expenditure.***

The Australian Energy Regulator should automatically include the relevant agreed allowable expenditure in the revenue allowance for the transmission business.

At the next regulatory reset, the actual capital spent on such projects should be included in the transmission business's Regulated Asset Base.

DRAFT RECOMMENDATION 15.4

The Australian Energy Regulator should ensure that, in the Australian Energy Market Operator's role as a transmission planner, its public reporting and planning processes are adequate, transparent and meet the National Electricity Objective.

DRAT RECOMMENDATION 15.5

The Australian Energy Market Operator should review and, where necessary improve, the technical aspects of its probabilistic processes, particularly those relating to low-probability, high risk events. In undertaking the review, the Australian Energy Market Operator should closely consult with network businesses and seek independent peer review of its technical methods.

DRAFT RECOMMENDATION 15.6

If the Standing Council on Energy and Resources does not accept draft recommendations 15.2 and 15.3, then it should implement a second best option in which:

- ***transmission businesses would retain the function of planning and making augmentation decisions***
- ***the Australian Energy Market Operator would set hybrid standards for connection points every five years, with standards that could fall as well as rise, and would provide advice on efficient investment to meet those standards***

- ***in consultation with network businesses, the Australian Energy Market Operator would develop peak demand forecasts. The Australian Energy Regulator would use these demand forecasts in its regulatory determinations in accordance with draft recommendation 8.4***
- ***the National Electricity Rules should be amended to allow the Australian Energy Regulator to accept the Australian Energy Market Operator's advice on the preferred network and non-network options and their cost as the default proposal, requiring the transmission business to show why its alternative was more efficient***
- ***the Victorian Government should not be required to relinquish its current planning framework, with the adapted hybrid model only applying to other jurisdictions. Other jurisdictions should be free to adopt the Victorian planning model.***

DRAFT RECOMMENDATION 15.7

Where necessary, the Australian Energy Market Operator should assist the Australian Energy Regulator in its compliance and auditing of transmission networks, to ensure that the agreed projects are completed and intrinsic network reliability is maintained.

DRAFT RECOMMENDATION 15.8

The Australian Energy Market Operator should act as the planner of last resort where it considers that underinvestment could expose the network to serious reliability problems, with the right to direct investment should the Australian Energy Market Operator believe that not to do so could seriously compromise the reliability of the National Electricity Market. The Australian Energy Regulator would act as an arbitrator in any disputes.

DRAFT RECOMMENDATION 15.9

The Australian Energy Regulator should review the Service Target Performance Incentive Scheme for Transmission to ensure the incentives and targets are consistent with the new National Electricity Market-wide reliability framework.

DRAFT RECOMMENDATION 15.10

Transmission businesses not already using this approach should transition to dynamic capacity ratings on all critical equipment.

Chapter 16 Distribution reliability

DRAFT RECOMMENDATION 16.1

The Standing Council on Energy and Resources should specify that reliability requirements for distribution businesses be included in the Australian Energy Regulator's Service Target Performance Incentive Scheme, replacing all existing jurisdiction-specific reliability settings.

- ***The reliability requirements should reflect the preferences of customers by using the estimated values of customer reliability, as spelt out in draft recommendation 14.1, and should be specific to the distribution business.***

DRAFT RECOMMENDATION 16.2

The Australian Energy Regulator should also make the following amendments to the Service Target Performance Incentive Scheme:

- ***reliability performance targets for the system average interruption duration index, system average interruption frequency index and momentary average interruption frequency index should be adjusted annually, according to rolling five-year average annual performance***
- ***revenue at risk should be negotiated as part of the Australian Energy Regulator's revenue determination process***
- ***the reporting and information component of this scheme should require distribution businesses to report their reliability performance at the zone substation level. Worst performing feeders should be identified as part of this process***
- ***reporting by all distribution businesses of performance against the parameters in the scheme should be published annually and be at least as detailed and comprehensive as current reporting mechanisms for distribution businesses in Victoria.***

DRAFT RECOMMENDATION 16.3

Where a distribution business can show that they are unable to technically comply with one or more parameters of the Service Target Performance Incentive Scheme, and where satisfied that the benefits exceed the costs, the Australian Energy Regulator should:

- ***approve the required revenue for the distribution business to install the necessary equipment***
- ***require compliance as soon as possible.***

Chapter 17 The role of interconnectors

DRAFT FINDING 17.1

The available evidence suggests that, given the existing network conditions, the current physical capacity of interconnectors is reasonably appropriate.

Chapter 18 The efficient use of interconnectors

DRAFT RECOMMENDATION 18.1

In the absence of any unintended consequences identified during current consultation processes, the Australian Energy Market Commission's 'optional firm access' package for generator access to the transmission network should be implemented.

- ***It should operate for a period of at least 10 years.***
- ***It should be monitored by the Australian Energy Market Operator for its effects on network planning and performance and, in concert with the Australian Energy Regulator, changes in observed patterns of generator bidding behaviour. Monitoring results should be made public annually.***

DRAFT RECOMMENDATION 18.2

After the optional firm access package has been operational for 10 years, a cost-benefit analysis should be conducted, with particular regard to the structure of the National Electricity Market at the time, the views of consumers, and any remaining barriers to the introduction of nodal pricing.

- ***If the analysis finds net benefits are likely, and no significant and insurmountable barriers or risks are identified, nodal pricing (including financial transmission rights) should be introduced with appropriate transitional arrangements and arrangements for disadvantaged consumers.***

Chapter 19 Identifying future transmission investment

DRAFT RECOMMENDATION 19.1

The Regulatory Investment Test for Transmission should not be amended to include indirect effects of investment decisions.

DRAFT RECOMMENDATION 19.2

In combination with the adoption of probabilistic reliability planning (draft recommendation 15.3), the Regulatory Investment Test for Transmission should be changed so that reliability is only assessed as a component of overall benefits and not as a separate criterion.

Chapter 21 Governance

DRAFT RECOMMENDATION 21.1

There should be an independent review of the resourcing and capacity of the Australian Energy Regulator to undertake all its functions, including whether there are impediments to its performance and options for improvement.

DRAFT RECOMMENDATION 21.2

The Australian Energy Regulator should have greater control over, and accountability for, the resourcing and management of its functions. It should:

- ***have its own separate budget sufficient to meets its role***
- ***submit a separate annual report of its performance***
- ***publicly reveal its strategy for improving its performance***
- ***have an independent capacity to negotiate resource sharing arrangements with a range of agencies, not just the Australian Competition and Consumer Commission***
- ***ensure that it establishes and retains the necessary specialist expertise to competently carry out its role, in accordance with draft recommendation 8.6***
- ***develop a program for regular ongoing communication and interaction with network businesses, their customers and other relevant stakeholders, with those interactions not just confined to periods of regulatory determinations.***

DRAFT RECOMMENDATION 21.3

There should be adequate ongoing funding of a single but broadly representative consumer body with expertise in economic regulation and relevant knowledge and understanding of energy markets. This body would:

- ***represent the interests of all consumers during energy market policy formation, regulatory and rule-making processes, merit reviews, and negotiations with providers of electricity networks and gas pipelines***

- ***subsume the role of the existing Consumer Advocacy Panel into its broader functions***
- ***be funded through a levy on market participants, drawing on the approach used to currently fund the Consumer Advocacy Panel***
- ***have a governance structure that involved a board of members appointed on merit, and an advisory panel to give the board advice on the needs of the mix of customers concerned.***

DRAFT RECOMMENDATION 21.4

The National Electricity Law should be amended to expedite the making of Rules arising from any appropriately conducted independent review relevant to the National Electricity Market and that are agreed by the Standing Council on Energy and Resources. This should be achieved by giving the:

- ***Australian Energy Market Commission the power to expedite Rule requests and***
- ***South Australian Minister a broader power to make Rules.***

Information requests

Chapter 5 Incentive Regulation and Benchmarking

The Commission seeks feedback on whether Chapters 6 and 6A of the Rules should be harmonised to support a common and coherent treatment of transmission and distribution networks (with differences confined to those areas where the different characteristics of transmission and distribution networks made these absolutely essential). Would this reduce the complexity currently caused by having two sets of Rules, lower costs for the Australian Energy Regulator, the Australian Energy Market Operator, the merits review body, and for consumers engaged in the regulatory process, and thus be more consistent with the National Electricity Objective? Would the benefits exceed the costs from any such transition?

Chapter 10 Technologies to achieve demand management

The Commission seeks feedback on any improvements to the process proposed for smart meter roll-outs, and how distribution businesses can contribute to the Australian Energy Regulator's assessment of the costs and benefits.

Chapter 11 Moving to time-based pricing for the distribution network

The Commission seeks further input from participants on the types of price paths that might be appropriate in transitioning to cost-reflective, time-based network pricing, including on:

- *any impediments to the early extension of such pricing to all large commercial and industrial users*
- *the benefits and costs (including that of a smart meter) from initially extending the use of 'time-of-use' network prices — employing peak, shoulder and non-peak tariffs — to all households and small businesses*
- *any ways that such prices could be usefully and quickly improved to be more targeted — such as through seasonal loadings — to reflect the costs of providing network services at peak times*
- *how quickly it would be appropriate to introduce greater geographic differentiation in network prices*
- *what indicators should be used to review how well the price transition process is progressing.*

It is also seeking further input on how the nature and speed of the transitional price path might be influenced by the costs and benefits of technologies (other than the smart meter itself) to improve responsiveness to price signals and assist with informed energy use decisions, including:

- *'smart appliances' that are enabled with a demand response capability (chapter 10) (such as to allow direct load control with a customer's agreement)*
- *'add-on' technologies, such as Home Area Networks, in-home displays, online portals and phone Apps, that draw on information provided by a smart meter to assist with a consumer's energy management*
- *information technology systems to communicate to customers, such as to provide notification of critical peak events.*

Chapter 12 Complementary reforms to support demand management

Given the package of draft recommendations in this report, the Commission seeks feedback on what (if any) barriers remain in the National Electricity Rules (or the Australian Energy Regulator's application of the Rules) that could impede an efficient level of demand management.

Chapter 15 Transmission reliability

The Commission seeks information about the potential benefits and costs of introducing contestability into separable augmentations of the network, as currently occurs through the Australian Energy Market Operator's procurement role in Victoria, and in parts of the United States. The Commission seeks evidence from participants regarding the costs and benefits of contestability including:

- *administrative and compliance costs*
- *the depth of the market (present and potential)*
- *the extent of efficiency gains available from competitive pressures from contestability for solutions to constraints (as opposed to contestability in detailed construction of a given solution)*
- *any ongoing cost inefficiencies caused by potentially additional separate owners and operators of the 'separable' assets connected to the network.*

The Commission also seeks participants' views regarding the costs and benefits of auditing facilities and processes in transmission networks. What alternative methods are there for the regulator to gain assurance about inherent reliability, in terms of whether transmission businesses are doing either, what they should do (for example maintenance), or whether they have done what they said they were going to do (for example augmentations)? What is international best practice in this respect? What powers should the regulator have if an audit suggests poor compliance?

The Commission seeks further input on the potential advantages and disadvantages of the Commission's suggested alternative to the Australian Energy Market Commission's hybrid planning model. How could the Commission's preferred model be improved? Since a key objective of a national planning framework is to avoid costly system-wide failures, to what extent do the different models vary in their capacity to achieve that goal?

Chapter 17 Role of interconnectors

The Commission seeks further evidence, and participants' views, on the impact of price separations between regions in the National Electricity Market.

Chapter 18 Efficient use of interconnectors

The Commission seeks participants' views about the extent to which flaws in a state-based hedging market distort the locational incentives of generators and large loads.

Chapter 19 Identifying future transmission

The Commission seeks participants' opinions as to whether the:

- *Regulatory Investment Test for Transmission should be applied to the replacement of existing assets*
- *Australian Energy Regulator could have an expanded role in the assessment of the Regulatory Investment Test for Transmission*
- *Regulatory Investment Test for Transmission could be used more formally in the Australian Energy Regulator's determinations.*

Chapter 21 Governance

The Commission seeks participants' views on the costs and benefits of the following measures concerning the location and funding of the Australian Energy Regulator compared with the arrangements proposed in draft recommendation 21.2:

- *removing the Australian Energy Regulator from the Australian Competition and Consumer Commission and creating a fully independent agency*
- *funding the Australian Energy Regulator through an industry (or National Electricity Market) levy.*

1 About the inquiry

1.1 What are the perceived problems?

This inquiry relates to electricity network services in the National Electricity Market (NEM), which covers all jurisdictions excepting Western Australia and the Northern Territory. The network comprises the wires, poles, easements, substations and other infrastructure used to transport power from generators to customers — with around 800 000 kilometres of lines extending from Tasmania to Queensland. Network charges account for around 40–50 per cent of an average household's electricity bill.

Network services are 'natural' monopolies — often still state-owned — with little scope in any given location for a competitor to duplicate the network efficiently. Without regulation, the resulting market power would lead to high prices and probably insufficient investment. Accordingly, government must regulate the prices and other aspects of these services to ensure reliable and affordable electricity. (In contrast, Australian governments have opened the generation and retailing segments of the electricity sector to greater competition, and the need for regulation in these segments has diminished.)

However, regulation of natural monopolies is not straightforward. Recent large increases in electricity prices — much of them attributable to growing network costs have sounded alarms about the effectiveness of current regulatory arrangements. Nationwide, retail electricity prices rose by around 50 per cent in real terms from June 2007 to June 2012 (chapter 2). Moreover, in a separate exercise from this inquiry, a Productivity Commission staff working paper found significant reductions in measured productivity in the Australian electricity sector over the past decade, which may have contributed to these price pressures (Topp and Kulys 2012; and chapter 2).

Against that background, the questions underlying this inquiry are 'Why have network costs been rising, will they continue to do so, is it justified, and if so, how can it be fixed?'

Price pressures posed by regulatory flaws, business inefficiency and legitimate costs

Regulatory arrangements for electricity transmission and distribution changed significantly in 2006 and 2008 respectively. As the intent of these regulations was 'to improve the environment for investment' (AEMC 2006a, p. iv; AER 2011a, pp. 3–4), some price increases would be expected. A reduction in productivity would also be anticipated because businesses must invest ahead of the full utilisation of capital.

Nevertheless, some key stakeholders claim that the regulations have substantial flaws and have inefficiently raised prices. These stakeholders include the Australian Energy Regulator (AER) with responsibility for regulating the NEM, various electricity user groups, and the Garnaut review of climate change policy. They attribute much of the price increase (and to some extent, the reductions in productivity) to two interrelated flaws in the post-2008 regulatory arrangements for electricity networks. They argue that:

- the design of regulatory incentives encourage excessive investment ('gold plating') in networks. Gold-plated investments increase the capital stock without a commensurate increase in output (although they may do so at a future date). Excessive investment leads to price increases and wastage of resources best used elsewhere in the Australian economy
- the regulated return to capital is excessive, directly leading to higher prices (as well as encouraging too much investment).

In that context, the AER said that some price rises it had allowed were 'difficult to justify', and arose from deficiencies in chapter 6 of the National Electricity Rules (the 'Rules') that it was obliged to enforce (AER 2011b, p. 4). The New South Wales Independent Pricing and Regulatory Tribunal (IPART 2012a, p. 4) has echoed this sentiment. Indeed, a body representing large commercial users of power, Major Energy Users, suggested that the relevant regulations had 'more than reversed the benefit gained from energy reforms initiated since the mid-1990s' (MEU 2011a, p. 3). In May 2012, the Queensland Government created an Independent Review Panel to oversee reform of power delivery in that state, with the rationale for the review being the 'blow out … in network costs, relative to service provision' (McArdle 2012, p. 1), though it did not attribute the alleged blow out to any particular source. Against this background, the AER and others have sought new regulatory approaches that they consider would better align investment and pricing with that which an efficient market would deliver. Benchmarking of businesses could play a role in those new approaches.

Not surprisingly, network businesses dispute that prices and costs are too high. They argue that the price increases only reflect the efficient response to the investments needed to meet the rising ratio of peak to average demand, the greater obligations to place lines underground, governments' requirements for higher reliability, and the need to replace a stock of capital that is reaching the end of its economic life. Of course, it is possible that both legitimate cost pressures and inefficiencies could be at work — an important issue for this inquiry. For example, an investment might be built to address peak demand, but be built in advance of its real need due to regulatory flaws.

Interconnectors or how the 'N' got into the 'NEM'

In addition to the above cost pressures, some claim there are shortcomings in the regulatory arrangements for the transmission lines ('interconnectors') that allow trade in power between eastern Australian states. Trading in power between regions has implications for electricity pricing, the required network infrastructure, system security and reliability, the need for generator capacity to meet end users' needs, and access by the broader network to new renewable power sources.

In his update on climate change, Professor Garnaut claimed that there was inadequate investment in interconnectors, a result he ascribed to fragmented and parochial transmission planning, market design flaws and other regulatory failures (Garnaut 2011a, pp. 153–55). While not widely regarded as a major contributor to recent price increases, there is concern that any such inter-regional barriers to trade have (and will increasingly) lead to inefficiency in the electricity industry. Underinvestment in interconnectors could put more pressure on prices and undermine the efficient use of renewable energy generators, which are suited more to some regions than others.

Considering the issues through two lenses

The Australian Government has requested that the Commission consider the above issues through two lenses:

- the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure
- the effectiveness of regulatory arrangements for interconnectors.

An important starting point is defining the nature of the market and its principal institutions.

1.2 Overview of the regulatory framework and its institutions

The NEM enables the trading of electricity throughout Australia, excepting Western Australia and the Northern Territory. It has several common features and institutions (figure 1.1). The overarching legal framework is the National Electricity Law (NEL), which is 'template' law enacted by South Australian law and adopted in all participating jurisdictions. Among other things, the NEL specifies the National Electricity Objective:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, safety, reliability and security of supply of electricity and (b) the reliability, safety and security of the national electricity system. (*National Electricity (South Australia) Act 1996*, v. 1.7.2012)

The institutions responsible for electricity policy and regulation also perform these roles for natural gas.

The responsibility for energy policy rests with the Standing Council on Energy and Resources (SCER), a recently formed Council of Australian Government standing council, which has assumed the functions of the Ministerial Council on Energy (MCE).[1]

The responsibility for making Rule changes rests with the Australian Energy Market Commission (AEMC), an independent national body funded by all state and territory governments (and employing around 60 people).[2] The AEMC makes rules that meet the objectives and other aspects of the NEL for the NEM (and gas for Australia as a whole), and undertakes market reviews and provides advice to SCER. The AEMC has a strictly limited independent capacity to initiate Rule changes, and responds to requests by other parties, such as the ministerial council, the regulator and end-users.

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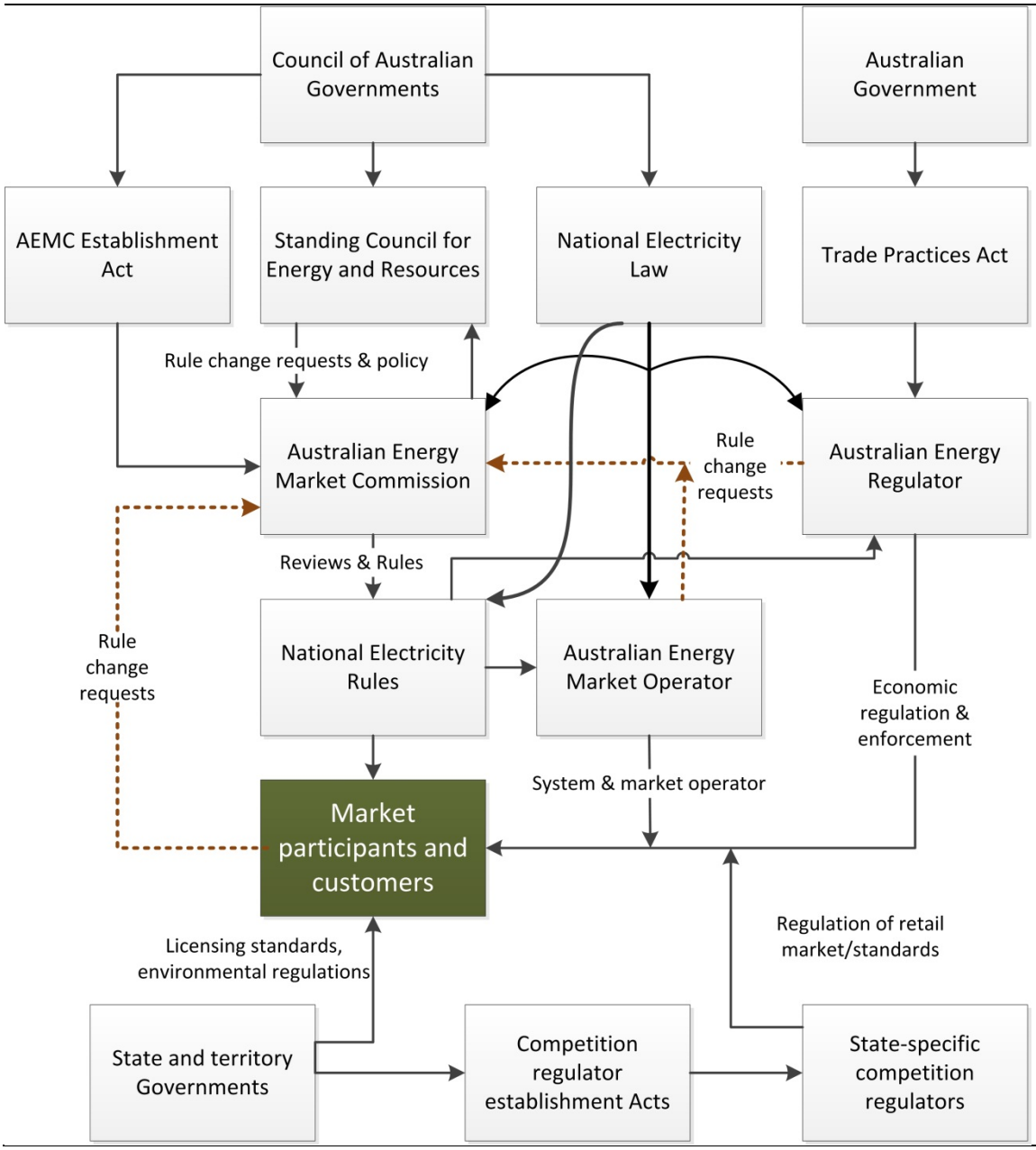
1 However, the National Electricity Law still specifies the MCE as the responsible COAG policymaker.

2 The AEMC was established under a South Australian Act, the *Australian Energy Market Commission Establishment Act 2004*. The Consumer Advocacy Panel was also established under this Act.

The regulator, the AER, is an independent Australian Government statutory authority, although it is located within the Australian Competition and Consumer Commission (ACCC).[3] It employs around 140 people of whom around 60 concentrate on electricity network issues. The AER regulates network providers, subject to the NEL and the detailed requirements of the Rules. Its main role is the determination of price limits and revenue caps, although it also ensures business compliance with regulations, and collects information on the energy market.

Figure 1.1 **The governance structure of the National Electricity Market**



3 The AER was established under Part IIIAA of the *Competition and Consumer Act 2010*.

The Australian Energy Market Operator (AEMO) is also an important part of the institutional arrangements for electricity (and natural gas).[4] It employs around 500 people. It is structured as a corporation with a skill-based board comprising government and private members. Its electricity responsibilities include managing the electricity market and playing a coordinating role in ensuring system security when demand exceeds supply. It takes bids and determines spot prices for generators, and ensures demand and supply are matched. AEMO also provides long-term planning reports and regional demand forecasts, and directly manages the planning of the Victorian electricity transmission system to ensure existing and expected demands are met. In other jurisdictions, the state government or asset owners undertake these functions.

State and territory governments and their regulators play a major role in regulating reliability standards and retailing in the NEM. State and territory governments also have various renewable energy policies that affect network businesses' options for addressing emerging bottlenecks in their systems. They are the owners of network services in Queensland, New South Wales, Tasmania and, in part, the ACT (and also own generators).

The existing regulatory arrangements for the NEM are detailed and prescriptive (with the Rules being around 1300 pages in length). The Rules consolidated and amended regulatory arrangements that previously operated at the state and territory level. Nevertheless, the 'N' in the NEM is a work in progress.

There is no uniform regulation of network services in the NEM, with major variations in the treatment of:

- the intra-regional transmission network, which comprises the high voltage components of the network that carry power over long distances within states
- the high-voltage transmission network ('interconnectors') used to transport power between states
- the distribution network, the lower voltage capillaries that deliver power at the local level. The distribution network accounts for the bulk of the infrastructure and costs. The distinction between lines and assets characterised as belonging to the distribution and transmission network varies between jurisdictions.

4 AEMO's functions are prescribed in the National Electricity Law, while procedures and processes for market operations, power system security, network connection and access, pricing for network services in the NEM and national transmission planning are all prescribed in the Rules. AEMO is fully funded by market participants. Ownership of AEMO is divided between government members (60 per cent of the votes) and industry members (40 per cent of the votes).

1.3 The Commission's approach to its terms of reference

The Commission's approach to this inquiry takes into account the specific issues raised in the terms of reference, and ultimately is underpinned by the general policy guidelines in the *Productivity Commission Act 1998*. Among other things, section 8 of the Commission's Act directs it to:

(a) improve the overall economic performance of the economy through higher productivity in the public and private sectors in order to achieve higher living standards for all members of the Australian community

(b) reduce regulation of industry where this is consistent with the social and economic goals of the Commonwealth Government

(c) encourage the development and growth of Australian industries that are efficient in their use of resources, enterprising, innovative and internationally competitive.

In pursuing these objectives, the Commission is required to recognise the interests of the community generally, as well as those (such as consumers or industries) likely to be affected by its proposals. The Commission may make recommendations on any matters relevant to the inquiry.

The Commission is aware that the regulatory environment is evolving and that the complex inter-relationships between changes in one aspect of the regulatory environment can have significant impacts elsewhere. There are numerous ongoing or recently completed reviews by the AEMC, the AER and others focusing on specific regulatory aspects of the NEM (table 1.1). Given this, the Australian Government asked the Commission to take account of work being undertaken by the SCER, the AEMC and the AER. In particular, the Government emphasised the relevance of the AEMC's review of transmission frameworks, proposals to change the Rules (of which the network rule changes proposed by the AER in late 2011 are the most significant) and the review of demand side participation. Reflecting these regulatory developments, the Commission has had ongoing discussions with the AEMC, the AER and the AEMO. We will continue to do so until finalisation of the report in April 2013.

Table 1.1 **What other major reviews are under way?**

Review	*Scope*	*Key dates*
AEMC reviews		
Transmission Frameworks Review	Proposals to reform the role and provision of transmission networks, including charging for the use of the transmission system, generator access rights, and planning	First interim report November 2011, second interim report August 2012, final report March 2013
Economic Regulation of Network Service Providers	Assessment of rule changes relating to the AER's approval of future expenditure and the regulated rate of return on capital	Consultation papers 20 October 2011 and November 2011, directions paper March 2012, draft determination August 2012, final report November 2012
Power of Choice	Demand side participation (or management), including the role of new technologies, such as smart grids, energy efficiency initiatives, and the efficiency of price signals in the NEM	Directions paper March 2012, draft report September 2012, final report November 2012.
Review of Distribution Reliability Outcomes and Standards (NSW)	Examines the extent to which investment in distribution networks reflect consumers' willingness to pay for reliability	Issues paper November 2011, best practices paper January 2012, draft report June 2012, final report August 2012
Review of Distribution Reliability Outcomes and Standards (National)	Analyse the different approaches to setting distribution reliability outcomes across the NEM and consider scope for national regime	Issues paper June 2012, draft report November 2012, final report four months after SCER comments on draft
Optimisation of Regulatory Asset Base and the Use of Fully Depreciated Assets	Assessment of whether existing rules about rolling forward capital assets is optimal	Consultation paper December 2011, draft determination June 2012, final report September 2012
Distribution Planning and Expansion Framework	Consultation on a rule change about annual planning and reporting of investments, demand-side engagement strategy, and a Regulatory Investment Test for Distribution	Consultation paper September 2011, draft determination in June 2012, final report October 2012
Potential Generator Market Power in the NEM	Definitions of any market power of generators for regulatory purposes	Technical paper December 2011, draft rule determination June 2012
Inter-regional Transmission Charging	Consideration of inter-regional transmission charging	Discussion paper Aug. 2011, final rule determination February 2013
Other reviews/major papers		
Limited merits review arrangements	Review of statutory merits appeal processes (requested by SCER)	Stage 1 report June 2012, Stage 2 report October 2012
Energy White Paper (Australian Government)	Policy framework to address challenges in the energy sector	Draft report December 2011, final late 2012
AER review of information collection processes	Aims to provide appropriate inputs into analytical tools	Implementation by June 2013
Senate Select Committee on Electricity Prices	Examines reasons for rising prices and appropriate policy responses	Completion by November 2012
Queensland Inter-Departmental Committee on Electricity Sector Reform	Government review of the source of electricity price rises and possible policy responses	January 2013

Against that background and the Commission's statutory obligation to consider the long-run benefits to the community as a whole, the Commission has taken a broad approach to its terms of reference. The Commission released an issues paper in February outlining this wide-ranging approach. Some participants' submissions addressed the broad set of matters raised in the paper,[5] while others considered that a narrower approach on benchmarking methods was preferable, and provided useful inputs mainly confined to this area. The Commission continues to believe that it can only discharge its responsibilities appropriately in this inquiry by taking a broad and holistic approach, while drawing on the other reviews taking place. The panel appraising the limited merits review regime similarly recognised the need to comment on the regulatory regime as a whole when considering any part of it:

> … the Panel is minded not to refrain from commenting on how different pieces of the policy jigsaw, of which development of the LMR [limited merits review] regime is just one, might fit together. (Yarrow, Egan and Tamblyn 2012a, p. 12)

Given this policy jigsaw, the inquiry:

- *considers the overall efficiency of electricity networks and the resulting impacts on costs for consumers — in keeping with the National Electricity Objective of meeting the long-term interests of consumers*. Benchmarking is a generic tool to measure inefficiency and to promote efficient conduct generally. So while one use of it is to set 'efficient' business prices in a regulatory determination, another common application is to assess efficient regulatory options — 'regulatory benchmarking'. Accordingly, the Commission has identified regulations outside the control of businesses that undermine efficiency and increase costs (and which may act as a greater drag on efficiency than managerial inefficiency). Where possible, the Commission has identified and quantified the things that matter to efficiency — the hallmark of benchmarking
- *takes account of the interdependencies between the regulatory, institutional, business governance and planning features of the NEM* (figure 1.2). These are pivotal to good overall outcomes for the community. There are significant dangers in bolting-on 'solutions' based on benchmarking and changes in interconnector policies if the surrounding regulatory edifice is rotten. For example, prescriptive reliability standards set at the state level may reduce businesses' capacity for efficient cost minimisation, while the current appeals process may undermine the usefulness of certain types of benchmarking analysis. Regulations that presume that network businesses will be motivated by profits, may not work effectively where government ownership removes or weakens such motivations. Interconnectors are just transmission wires,

5 For example, the Major Energy Users (sub. 11); the Consumer Action Law Centre (sub. 5); AEMO (sub. 32); and the Energy Supply Association of Australia (sub. 23).

privileged with a special name because they bridge regions in the NEM. Optimal interconnector policies depend on the planning framework for transmission generally, its pricing and the degree to which policies can limit game playing by some generators. Accordingly, any assessment of regulatory arrangements for interconnectors necessarily overlaps with the regulatory issues for intra-regional transmission and, to some extent, the conduct of generators

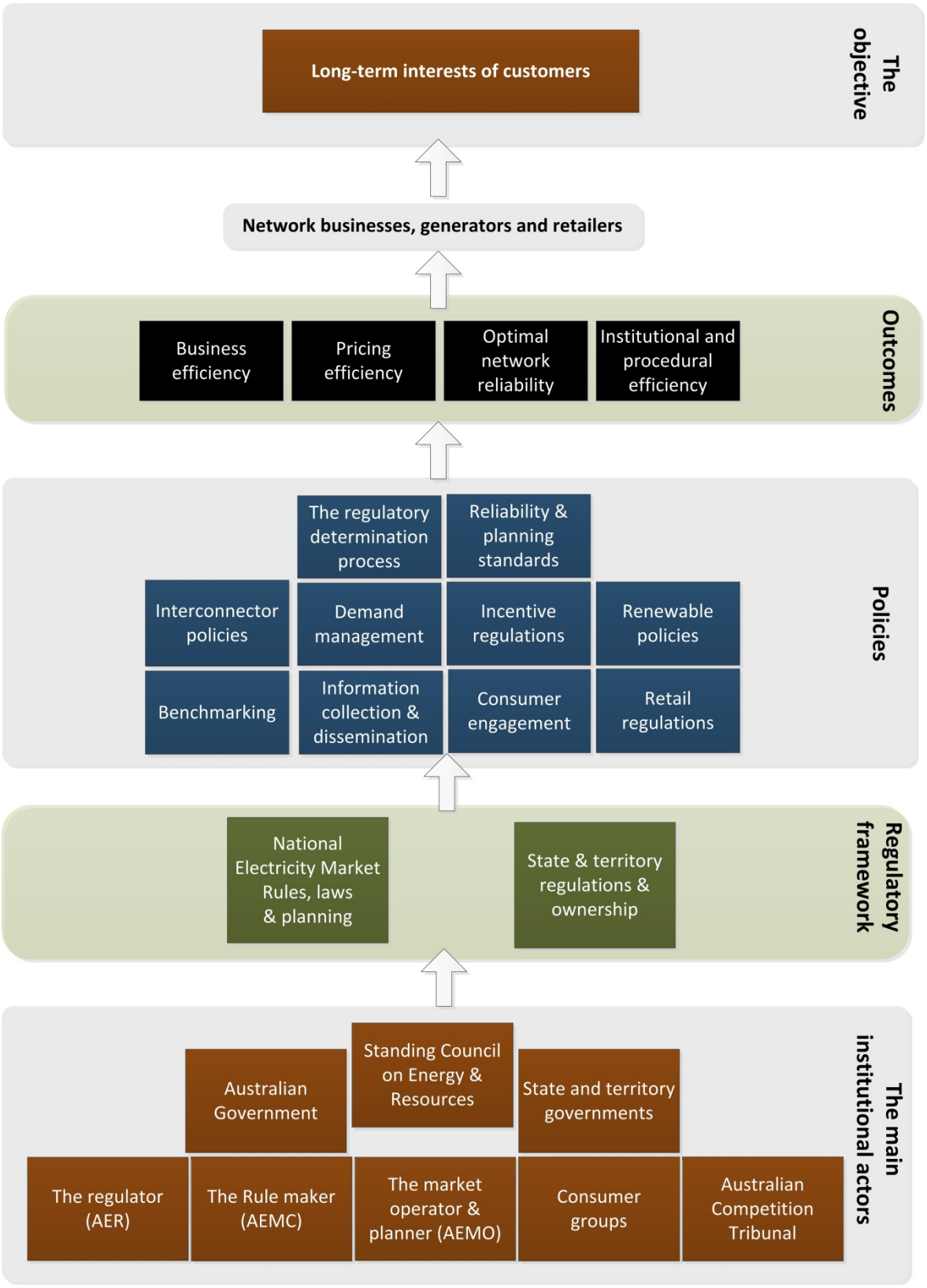
- *analyses the best institutional framework for achieving efficient outcomes*. Regulatory reform involves much more than writing new laws and regulations, but requires facilitating institutions and processes. For instance, to meet its objectives effectively, a regulator must have independence (financial, cultural, legislated and perceived), expertise and adequate resources, and use the right processes. The more power and discretion given to any agency in using benchmarking to set prices, the more important it is that the institutional and governance arrangements are sound. Similarly, a sound appeals process is required, on the one hand, to prevent gaming by businesses and, on the other, to minimise regulatory errors
- *considers the future* — including potential imminent Rule changes, changing technologies and carbon pricing — when making judgments about regulatory arrangements. However, the Commission is also aware that the current arrangements are relatively new. Any radical reforms should be considered carefully given the uncertainties and risks that these entail.

Consultations

Beyond the Commission's ongoing consultations with the AER, AEMC and AEMO, the Commission also consulted with state and territory governments and their competition regulators, various Australian Government agencies, transmission and distribution businesses, generators, consumer stakeholders, and other interested parties in undertaking the review. The Commission also considered international regulatory experiences in achieving efficient investment and pricing in networks and interconnectors, and held discussions with overseas experts and regulators in the United Kingdom and the United States.

To encourage and guide submissions, the Commission released an issues paper on 23 February 2012 outlining the key matters on which it was seeking comments and information from participants. The Commission received 44 submissions prior to publication of the draft report. The Commission thanks all those who have contributed to this inquiry.

Figure 1.2 **Everything in electricity policy is interconnected**



The Commission will hold formal public hearings following release of this report and seek a further round of submissions before completing the final report by April 2013.

1.4 A guide to the report

Introductory material

Electricity networks are one of Australia's most important, costly and extensive forms of infrastructure. The desirability, feasibility and design of any new policies for benchmarking and interconnectors is dependent on the nature of electricity networks and their associated regulatory arrangements. In that context, chapter 2 sets out the characteristics of electricity networks, the broad nature of the existing regulatory arrangements across the NEM, and describes the industry's aggregate performance under current regulatory arrangements.

While most argue that there are strong grounds for regulation of an essential service with natural monopoly characteristics, it is important to understand how and why the problems are manifested, since that affects the design of the regulatory antidotes. This also helps identify the appropriate objectives of, and limits to, regulation — including the role of benchmarking in regulatory determinations. Recently, this has been an area of some controversy. Chapter 3 addresses these issues.

Using benchmarking to set regulated prices and revenues

Benchmarking comprises a set of tools for measuring business efficiency and performance against some best practice benchmark, and for creating incentives (financial or political) for managerial efficiency and for best practice regulations. Chapter 4 describes benchmarking and its methodologies, strengths and limitations.

Some envisage that benchmarking could play a larger role in the regulatory regime. However, the benefits of an expanded role depend on whether the design of the regulatory regime frustrates its effective use. A benchmark, no matter how accurate, is of little value if the regulator is unable to use it or if it does not influence the behaviour of the regulated firm. Chapter 5 examines these issues, considering any flaws in current incentive regulations, investment biases in the weighted average cost of capital, and the impacts of competitive neutrality on state-owned corporations.

It is useful to consider whether there is a prima facie case that significant inefficiency exists among network businesses. That would shore up the basis for further benchmarking — and for it to play a greater role in future regulation. Chapter 6 considers existing studies of network efficiency and undertakes some preliminary analysis of the performance of network businesses (an exercise that also sheds light on the practicality of undertaking benchmarking). Due to data limitations and the problems of undertaking precise benchmarking, the results are necessarily not authoritative. The Commission has used a variety of data sources and information to make its judgments in this area.

State-owned corporations remain the most important suppliers of network services. These businesses face particular challenges. It is important to assess the degree to which ownership makes a difference to productivity performance and the extent to which such businesses respond to incentive regulations. Chapter 7 considers this question, drawing on chapters 5 and 6, as well as other evidence.

In light of the findings of chapter 4 to 7, chapter 8 examines how the regulator might use benchmarking in regulatory determinations.

External factors constraining business efficiency — regulatory benchmarking

As emphasised earlier, many sources of inefficiency in networks may be outside the control of the businesses themselves. For example, network businesses do not set reliability standards, feed-in tariff rates, demand management incentive schemes, or retail price regulations. Weighing up existing regulatory and policy measures against best practice — regulatory benchmarking — can reveal the degree, if not the precise magnitude, of the costs associated with policy-induced inefficiencies, and also the direction for reform. Any benchmarking of managerial inefficiency aimed at assisting the regulator to determine prices and revenues must also attempt to control for the impacts of factors that a business must take as given. Accordingly, the Commission has considered the degree to which:

- demand management can improve the efficient investment in, and operating costs of, networks. Chapter 9 examines the problems posed by prices that do not fully reflect the costs of infrastructure (especially during critical peak demand periods), and benchmarks the potential cost savings from improved policy. However, the size and timing of these potential savings depend on a suite of coordinated reforms and sensible processes. The critical requirements are:
  - technological change (such as smart metering) that underpin the capacity for network businesses to set time-based charges for their services, and retailers

to develop pricing packages that reflect the charges passed onto them from the network businesses (chapter 10)

  - the long-run adoption of cost-reflective pricing of network services, but accompanied by processes that ensure proper consultation with all stakeholders, that drive a coherent transition to that long run, and that address concerns about the effects of change on vulnerable consumers (chapter 11)
  - changes to the way in which the regulator constrains prices or revenues over the regulatory period, and the implementation of policies that motivate retailers to develop products and tariffs that allow improved demand management (chapter 12)
- distributed (small-scale) generation can avoid or defer network investment by helping to relieve network congestion, meet peak demand or improve system reliability (similar to the goals of demand management). However, the appropriate role of distributed generation depends on whether there are any regulatory obstacles to its use, the extent to which it has adverse effects on the network (which has largely been designed for one-way flows of power), and whether there are subsidies or other measures that distort people's choices in this area (chapter 13)
- reliability standards affect the costs and efficiency of electricity network businesses. Chapter 14 provides a framework for assessing reliability issues and diagnoses the problems of the current arrangements. While there are some overlapping factors, reliability issues vary considerably between transmission (chapter 15) and distribution networks (chapter 16), and so too do the optimal policy approaches.

Interconnectors

Chapter 17 considers the role of interconnectors in the NEM, the framework for assessing any problems, and the magnitude and implications of any current inefficiency. Chapter 18 examines the efficient utilisation of interconnectors, including the potential long-run adoption of more fundamental pricing reforms. Chapter 19 addresses the frameworks for identifying future interconnector investment (and because of their inextricable links, transmission networks generally).

Most interconnectors are 'regulated', which means that the AER determines the revenue they receive and how parties can access them. However, at the commencement of the NEM, it was envisaged that unregulated private interconnectors (often called 'merchant' interconnectors) would play a more

significant role. An important question is whether the virtual absence of merchant interconnectors reflects aspects of the regulatory arrangements, and whether they could or should play a role in linking the regions (chapter 20).

Governance and institutions

Policy and practice sits within an institutional framework. Chapter 21 assesses the best institutional structures for progressing reform, including the potential to empower consumers and the need to ensure the regulator is funded adequately and has sufficient access to expertise. (Other institutional arrangements — such as those relating to the role of AEMO in planning and demand forecasting — are covered in previous chapters). Implementation issues are discussed in the relevant chapters and summarised in the overview to this report.

Appendix A describes the conduct of the inquiry and participation by various stakeholders. The report is accompanied by several other appendices that address particular issues raised in lesser detail in chapters. These are on the Commission's inquiry web page.

2 The structure and performance of the National Electricity Market

Key points

- The NEM comprises six groups of direct participants: generators, ancillary services, transmission and distribution networks, retailers and customers.
- The structure of the electricity supply industry has shifted over time, with vertical separation of generation and retailing from the natural monopoly elements of the industry, and horizontal integration of network businesses. However, increasingly generators and retailers have integrated to form 'gentailers'.
- Collectively, state governments are significant asset holders — owning all transmission and distribution assets in Queensland, New South Wales and Tasmania.
- Network services are the most costly single component of electricity supply, accounting for around 45 per cent of total electricity prices.
- From June 2007 to June 2012, real Australian retail electricity prices rose by around 50 per cent, with network costs playing an important role in the last few years, particularly for New South Wales.
- Any price increases in network services have particularly large relative effects on poorer households, one of the motivations for concerns about price pressures.
- Residential network charges are diverging between jurisdictions. Network charges in New South Wales, Queensland and South Australia are projected to be around double those in Victoria in 2013-14.
- Power consumption per customer fell by around 2.5 per cent in both 2010-11 and 2009-10. In contrast, peak demand to average demand has been rising over time.
- New patterns of network development may occur as generation shifts away from conventional energy sources, with cost and planning challenges.
- While rising network price pressures partly reflect peak demand trends, more undergrounding of lines, higher reliability requirements and the need for asset replacement, this does not mean that there is no scope for efficiency improvement.
- Even modest improvements in network business efficiency could produce billions of dollars of economic benefits to Australians.
- Network services are a ubiquitous input for all industries, accounting for around 1–1.5 per cent of the value of inputs for most industries. Given this dispersion of interests, it would be hard for a representative user group to form spontaneously and to negotiate from a position of power with network businesses.

This chapter provides a brief overview of the National Electricity Market (NEM) as a whole, covering the:

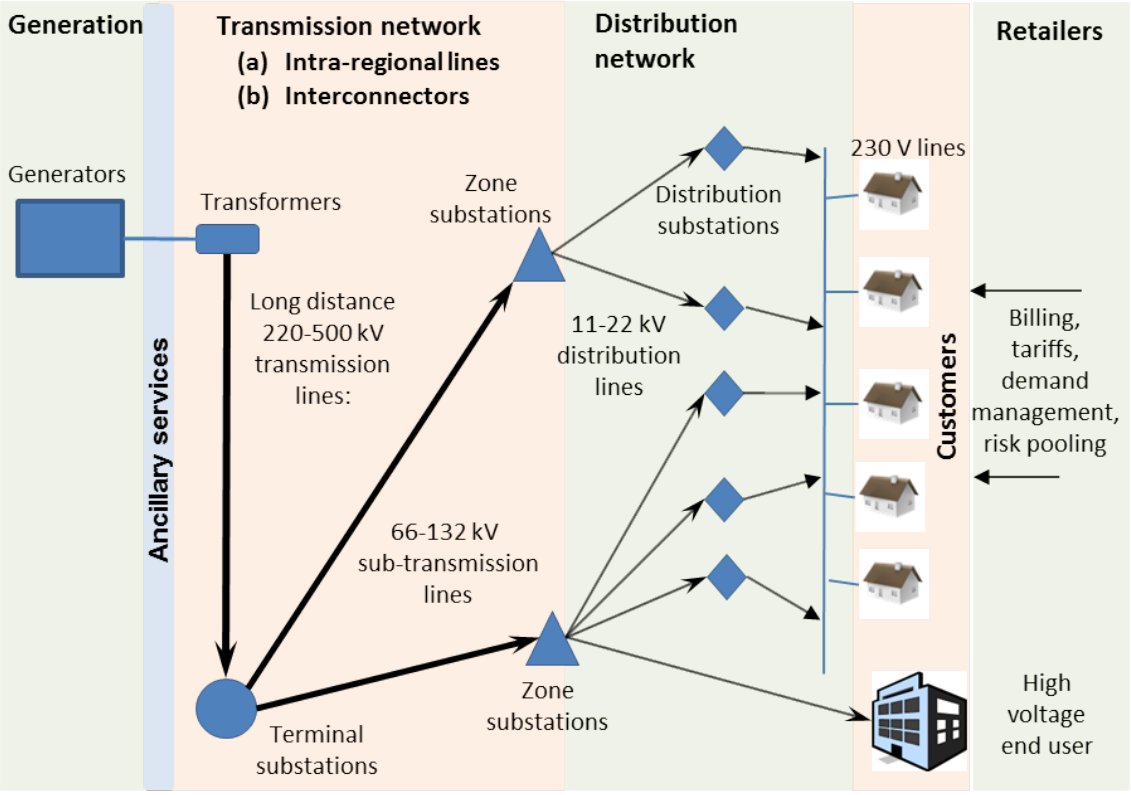
- structure of the NEM, including brief coverage of some recent developments in generation and retailing that are relevant to networks (section 2.1)
- scale of the network and its costs — whose significance explains why cost pressures in this part of the electricity industry have large impacts on the prices customers face (section 2.2)
- characteristics of demand (section 2.3). This is important from many perspectives. It affects the capacity for consumers to exercise countervailing power and partially motivates new approaches to involve customers in the regulatory process (an issue explored in chapter 21). It shows why benefits from any lower network costs cascade across the entire community. And, given its nature as an 'essential' service, any cost pressures on network services have particularly adverse effects on low-income households, underlining why network cost increases are so sensitive for the community
- recent price changes (section 2.4) and their proximate causes (section 2.5)
- basic reliability performance of the network (section 2.6), since customers value uninterrupted power and good frequency control. (In their own right, government requirements for improved reliability have also been a significant source of cost pressures.)
- potential economic gains from improving the performance of the network — which motivates the value of the policy reforms outlined in subsequent chapters (section 2.7).

This chapter does not provide a detailed description of the regulatory environment governing networks, since this is addressed in a focused way in the policy chapters that follow.

2.1 The structure of the National Electricity Market

The NEM is a highly elaborate system for managing the production and transport of power throughout eastern Australia. On the supply side, there are four principal parts of the system: generation, network transmission and distribution services, and retail services (figure 2.1).

Figure 2.1 **The structure of the NEM**



Data source: Based principally on Powercor (2006).

The network

The electricity network (the focus of this inquiry) is a massive transportation system that takes the power from generators and delivers it to an end user's electricity switchboard. Simplifying, it comprises several parts:

- transformers, which take the power from the generators and converts it to high voltage (which lowers transmission losses when power is transported over any significant distance)
- high-voltage transmission lines — mainly strung overhead on steel lattice towers — that transport power over long distances. These include intra-regional lines and inter-regional lines (interconnectors).
- substations that convert very high voltage to lower voltage
- the myriad of lower-voltage substations, poles, trenches and wires that make up the distribution system — the 'capillaries' of the system — which distribute lower voltage power to multiple users in local areas

- the provision and maintenance of certain services, such as street lighting
- meters at the business or household that record electricity consumption and, in some cases, provide real time control of the delivery of power to customers, and provide information on time-of-use prices to customers and usage patterns to suppliers. While distributors are mainly responsible for metering equipment and associated services, there is some competition from other businesses (Metropolis 2011).

Although the information technology systems to control the network are sophisticated (such as those deployed by the Australian Energy Market Operator (AEMO) and network businesses), much of the *costs* of the electricity network involve relatively mature technologies, such as trenches, poles and wires (a feature it shares with telecommunications). The research and development undertaken by electricity networks was around $50 million in 2008-09 (just a little more than in the log sawmilling and timber dressing industry) (ABS 2011a).

Regulatory arrangements for networks

The regulatory arrangements for networks are highly complex. (The Australian Energy Regulator (AER) provides an accessible summary for readers of the key aspects of the regulatory framework.)[1] The National Electricity Law and the Rules set out the NEM-wide arrangements for the economic regulation of networks. Reliability standards and planning are largely decentralised — and are overseen by the network businesses, state and territory regulators and their governments. The relevant aspects of these arrangements are discussed in the chapters that follow and are, accordingly, not duplicated in this chapter. However, most of the roughly 1300 pages of the Rules have little bearing on this inquiry, as they cover market dispatch and financial settlement procedures, prudential requirements for market participants, administrative functions, power system security, connection arrangements, and system standards, among other matters.

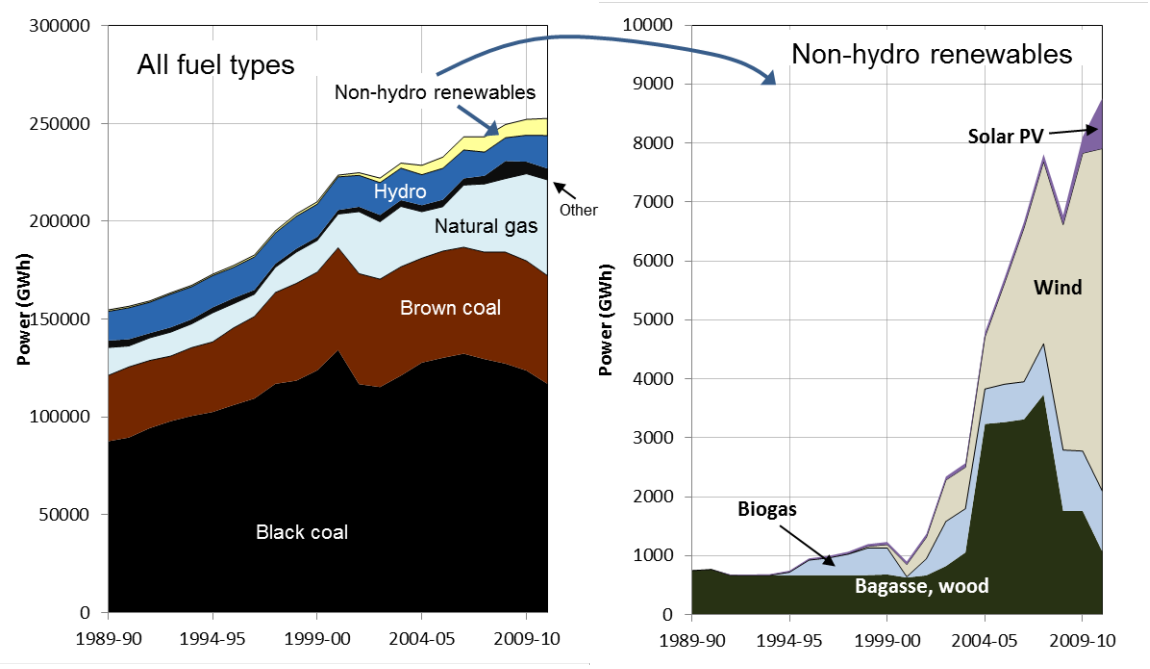
Generation and the spot market for electricity

Most power in the NEM is generated using coal (80 per cent of output) or gas (12 per cent out of output) as their fuel source (AER 2011b, p. 27). However, the renewable energy target and carbon pricing are designed to encourage investment in more diverse sources of generation. While only accounting for 4 per cent of current power capacity (and 3 per cent of output) in 2011, wind generation is an

1 AER (2011b, pp. 57–60, 73–5).

increasingly important source of power (figure 2.2). Wind generation accounted for around two thirds of investment in new installed (summer) capacity in 2010-11, around 45 per cent of the new capacity associated with committed investment in June 2011 and 65 per cent of capacity in publicly announced projects (table 2.1). In South Australia, wind accounts for nearly one quarter of nameplate capacity and has sometimes accounted for around 85 per cent of output (but its overall contribution to energy output in that State is around 20 per cent).[2] In contrast to the burgeoning role of wind generation, little new hydro capacity has been installed in the last decade, with similar future prospects. (However, existing hydro-electricity plants are important sources of power in Tasmania, Victoria and New South Wales.) In 2010-11, solar generation provided 850 GWh of energy output, or 0.34 per cent of Australia's total generation output in this period (BREE 2012).

Figure 2.2 **Growth in generation by fuel type**
1989-90 to 2010-11



Data source: BREE (2012).

The greater diversity of generation has several implications for the electricity network. Much of the existing transmission infrastructure is close to the raw materials used to power conventional generators (such as the coal reserves in Latrobe Valley and the Hunter Valley, and the rainfall and topography of the Snowy Mountains). That means that new transmission infrastructure may be required to connect renewables generators to the grid, sometimes across state boundaries. That

[2] AER (2011b, p. 27) and BREE (2012).

then raises the issue of the best arrangements for regulating interconnectors (and likewise transmission generally — chapters 17 to 20). An associated issue is that while entry barriers to new generation are lower, incumbent generators may sometimes wield market power, affecting whether and where network businesses build new transmission lines.

Table 2.1 **Investment in generation: installed and anticipated**

Share of nameplate capacity by investment category[a]

Fuel type	*Installed in 2010-11*	*Announced in 2011*	*Committed in 2011*
	%	%	%
Brown coal	0.0	4.1	0.0
Natural gas	35.5	26.8	43.7
Bagasse/black coal	0.0	2.3	10.7
Geothermal	0.0	1.3	0.0
Solar	0.0	1.7	0.0
Hydro	0.0	0.1	0.0
Wind	64.5	63.6	45.4
Methane	0.0	..	0.1
Total	100.0	100.00	100.00

[a] Where a range of nameplate capacity (MW) was provided in the data, the lowest value was used. A generation investment is categorised as 'committed' by AEMO if most of the [pre-conditions for future investment are in place (such as finance, land purchase, and contracts to build). Announced projects are ones that have a lesser degree of certainty, but an intention to build has been publicly made.

Sources: AEMO (2011a); AER (2011b, p. 44).

The price of wholesale electricity is determined in a spot market in which demand and supply are constantly matched. Every five minutes, generators bid to supply a given quantity of power. With a few exceptions, all power supplied to the grid must be supplied through the wholesale spot market. AEMO chooses the combination of offers that minimises the cost of supplying power, taking account of generation marginal costs, losses due to electrical resistance and heating of conductors along the transmission lines (transmission loss), and whether there is congestion on the relevant transmission lines. In meeting a given amount of demand, AEMO despatches the lowest priced bids of power first (typically that of a large coal-powered generator that must run for 24 hours a day), meeting residual demand with increasingly costly power. During peak demand periods or where there are significant outages, that residual power is supplied by switching on high-cost 'peaking' plants — usually gas turbines burning natural gas. Some generators are built only for extreme events, such as heat wave conditions, and may be idle for all bar a few hours a year.

The marginal cost of the last (highest priced) megawatt of electricity despatched by AEMO determines the spot price. All generators receive the same spot price for

their despatched power, regardless of their bid price. Accordingly, a low bidder will typically receive revenue well above the marginal cost of their despatched power. Such a premium is required to provide an ex ante incentive for investment in generators, though changes in demand, fuel costs and competitive technologies mean that ex post a generator may either receive more or less than was needed to justify the initial investment.

AEMO sets a spot price floor (-$1000 per MWh) and ceiling ($12 900 per MWh).[3] The former is required because it can be costly to turn a generator off, so that a generator may want to guarantee despatch by bidding at negative prices (although this feature also has some unintended impacts as discussed in chapter 18). The latter is required because demand is very unresponsive to price over the very short run (due to the way in which prices are signalled to customers and their capacity to respond to them). Without a price ceiling, prices would rise astronomically during extreme peak load events or times of reduced base load capacity (Frontier Economics 2010a), as would wholesale electricity costs. There is some concern that a large generator could use transient market power to withhold enough low-cost base load output to raise market prices for the residual amount of power it provides. The ceiling places a limit on that capacity.[4] There is a further safeguard provision that limits the price to $300 per MWh (the administered floor price) if high spot prices are sustained.[5]

Retailing

The other major segment of the system — retailers — purchase electricity from the national market, pay access fees to networks, and sell power to end users. They manage billing, develop packages of services tailored for different customers and, through various risk management techniques, insure final customers against volatile electricity spot prices.

In contrast to network services, there is a genuine capacity for entry into retailing, and therefore greater scope for effective competition. Customers are able to choose

3 The market price cap re-calibrated by AEMO annually based on a formula set down in the Rules (clause 3.9.4).

4 The story is more complex than this because investors in generators will typically reduce their risks from fluctuating spot prices through derivative contracts. As noted by Frontier Economics, generators usually enter into swap contacts for most of their capacity and so do not benefit from pushing up the spot price for their swap contracted capacity (2010, p. 13), limiting the gains from strategic behaviour.

5 Clause 3.14.2 of the Rules. Unlike the market price cap, the administered cap is not indexed, but can be reviewed from 'time to time'.

their own retailers ('full retail contestability') in all NEM jurisdictions apart from Tasmania. Many retailers specialise in providing services to larger customers only, with less than 50 per cent of retailers providing services to small customers (AER 2011b, pp. 105–6).

In most jurisdictions, a few retailers provide most of the services, with a particularly high concentration of supply in Tasmania and the ACT (AER 2011b, p. 103). Victoria has the greatest level of competition, as indicated by customer switching patterns and a less concentrated market structure.

There has been an increasing shift to harmonised retail regulations across the NEM. In 2006, the Council of Australian Governments agreed to develop a new national framework governing the sale and supply of electricity and natural gas to retail customers. The goal was to reduce regulatory burdens for energy businesses operating across jurisdictions, while retaining appropriate consumer protection. A lengthy process of consultation, negotiation and regulatory development ensued after the 2006 agreement.

A National Energy Customer Framework (NECF) has now been (notionally) created. The NECF transfers several major regulatory functions currently performed by the relevant jurisdictions to the AER, including:

- monitoring compliance and enforcing breaches of the National Energy Retail Law and its supporting rules and regulations
- authorising energy retailers to sell energy, and granting exemptions from the requirement to be authorised
- approving retailers' policies for assisting with customers facing hardship
- providing an online energy price comparison service for small customers (see the energy price comparison website, Energy Made Easy)
- administering a national retailer-of-last-resort scheme, which protects customers and the market if a retail business fails
- reporting on the performance of the market and participants, including on energy affordability, disconnections and competition indicators.

As in other aspects of the NEM, the 'N' in the NECF remains somewhat ethereal. Implementation across jurisdictions has been slow. By July 2012, the largest states had yet to pass the legislation (with the law commencing only in the ACT, South Australia and Tasmania). As in the case of network regulation, the NECF excludes Western Australia and the Northern Territory.

Moreover, the AER will only take over the non-economic functions of retail regulation, leaving state arrangements for retail price regulation in place. The NECF also provides scope for jurisdictions to carve out aspects of the National Energy Retail Law. For example, the Victorian Government will not adopt the prepayment meter regime and will maintain certain consumer protections that it considered superior to those in the NECF (DPI 2012a).

Retail price regulation remains in all jurisdictions other than Victoria. Under regulated arrangements, customers can choose to purchase their electricity from the 'non-market' retail segment, which is subject to price controls by the relevant state regulator, or the market segment, in which there is pricing flexibility. In 2006, the Council of Australian Governments agreed to remove retail price regulations in any jurisdiction where the Australian Energy Market Commission (AEMC) found competition was effective.

However, that process has not moved quickly. Jurisdictions have not always acted when the AEMC has proposed de-regulation following its assessment that competition was effective. The South Australian and the ACT governments did not accept the AEMC's recommendation to deregulate prices. In June 2011, the SCER announced that future reviews would be New South Wales in 2012, Queensland in 2013, South Australia in 2015, the ACT in 2016, and Tasmania no sooner than 18 months after full retail contestability is implemented. (The Tasmanian Government has responded to a 2012 report issued by an expert panel on the electricity supply industry by announcing full retail competition from 1 January 2014.)

As in other aspects of electricity supply, imperfections in one part of the system carry over to other parts. By acting as an obstacle to cost-reflective pricing and incentives for adopting direct load control, retail price controls adversely affect the efficiency of investments in electricity network and generation (chapter 12). As emphasised in chapter 1, this affects the use of benchmarking in incentive regulations, but also raises the importance of testing the cost effects of different regulatory regimes across the NEM.

Benchmarking in retailing

Benchmarking has been incorporated into the national approach to retailing (Acil Tasman 2011 and EnergyConsult 2010), and is based on survey data from more than 5000 households on their power use. The purpose of the 'Electricity Bill Benchmarking initiative' is to provide households with information on their relative use of power given their household characteristics, so that they can make informed choices about their electricity use.

The initiative reveals some of the inconsistencies in the goals of policies across the electricity supply industry. Relatively short period of peak use, mainly during hot summer days, are responsible for a significant amount of network infrastructure investment (chapter 9). However, the information provided in the retail benchmarking exercise concerns total power usage, which is a poor proxy for expensive peaky use. Accordingly, the information does not inform consumers about the true underlying costs of their power usage. If critical peak pricing were introduced — as recommended by the Commission — the retail benchmarking model would need to be elaborated. The Commission has recommended surveys to estimate the value of lost load for setting appropriate reliability standards (chapter 14). These surveys could replace the existing electricity bill benchmarking surveys, and would provide better information to assist informed choice by consumers

Other services

Outside these major parts of the system, there are some direct transmission lines from generators to major industrial users, some industrial co-generation feeding into the grid, increasing micro-generation at the customer end (such as solar panels) and an array of financial and technical services (for example, in financial instruments that address the risks of generators and retailers and ancillary services[6]).

Ownership and linkages

Competition reform in the 1990s led to the disintegration of the management of the electricity system in each jurisdiction by a single vertically integrated state-owned business (spanning generation, transmission, distribution and retailing) in each state and territory.

Generation and retailing are now open to competition, while the natural monopoly segments of the industry — network services — remain heavily regulated and are often still owned by governments. The New South Wales, Queensland and Tasmanian governments own the distribution networks in their states, whereas private entities own the South Australian and Victorian distribution networks. The

6 Ancillary services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes (AEMO 2010a). AEMO operates eight separate markets for the delivery of frequency control ancillary services (akin to the wholesale energy spot market) and purchases network control ancillary services from transmission businesses and system restart ancillary services under agreements with service providers.

ACT distributor is part government-owned. Overall, governments own 75 per cent of distribution assets in the NEM (and a similar share of transmission assets).

Moreover, there are still strong ownership and management links between parts of the system. Vertical integration between generators and retailers — 'gentailers' — is becoming increasingly common (AER 2011b, pp. 12–13, pp. 106–8; Pearce 2011, p. 16). For example, Origin Energy — one of Australia's largest energy businesses — has integrated operations spanning gas exploration and extraction, gas pipelines, power generation and electricity retailing. AGL Energy and TRUenergy also have interests in gas production and/or gas storage that complement their interests in gas fired electricity generation and energy retailing.

State governments also sometimes jointly own transmission, distribution, generation and retailing. For example, the Tasmanian Government owns the sole transmission business in that State (Transend), all generation (Aurora Energy and Hydro Tasmania), the only distribution business (Aurora Energy), the dominant small customer retailer (Aurora Energy) and a major business retailer (Momentum Power). However, following a recent review (Electricity Supply Industry Expert Panel 2012a), the Tasmanian Government will sell Aurora Energy's retail arm (Green 2012). In most other states, there is usually greater scope for competition from private businesses in the contestable parts of the system (generation and retailing).

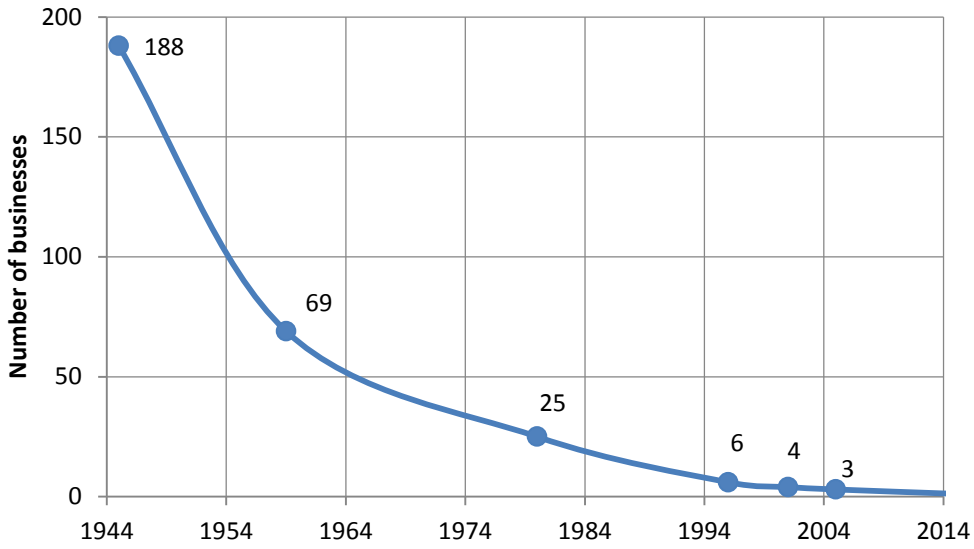
The vertical separation of networks from the other parts of the electricity system has had many desirable benefits, including the capacity to develop a genuinely national market and to provide stronger market-based incentives for efficiency. However, it has also diminished the capacity for coordination of the various parts of the networks and has reduced economies of scope.[7] For example, exploitation of transmission congestion; weakened incentives for demand management; difficulties in planning; and the requirements for sophisticated financial hedging instruments reflect the problems that vertically separated businesses have in transacting with each other. Many of the regulations in the NEM can be seen as alternatives ways of encouraging efficient transactions between businesses that no longer have aligned interests. This poses fundamental challenges for regulatory design — some of which have not yet been fully resolved, such as regulations for smart meter rollouts (chapter 10) and strategic bidding behaviour by generators (chapter 18).

While policy reforms have required vertical disintegration, governments as owners have encouraged horizontal integration of network distribution businesses. This

[7] A consequence explored in a large literature on the economics of integration in electricity and other similar utilities (summarised in Lafontaine and Slade 2007 and Saal 2011).

appears to reflect significant economies of scale in networks[8] and the progressive shift from local small generators to large-scale generators more remote from population centres. In New South Wales, the merger process has been the most pronounced (figure 2.3). However, mergers involving common management appear to have been confined to businesses within state boundaries, reflecting the importance of state ownership (and a state-specific orientation to service delivery).[9] There is no obvious reason why common management of businesses should be constrained by state borders. In the United States — at least among transmission businesses — the story is quite different. For example, American Electric Power owns transmission infrastructure throughout the United States and Canada. This raises the question of whether state-ownership may be a barrier to efficient horizontal mergers (chapter 7).

Figure 2.3 **Progressive merger activity**
NSW, distribution businesses 1945-2014



Data source: NAS (2009), *Issues in relation to the Availability and Use of Asset, Expenditure and Related Information for Australian Electricity and Gas Distribution Businesses*, paper for AEMC, August.

8 See for example, Farsi et al. (2010) and Kwoka (2004).

9 Currently, Essential Energy provides some services outside New South Wales, principally in the area around Goondiwindi in Queensland, Victoria and the ACT (Essential Energy, sub. 30, p. 3). There is common ownership (compared with common management) among private network businesses. For example, Cheung Kong Infrastructure and Power Assets Holdings and Spark Infrastructure jointly own Powercor, Citipower, and ETSA Utilities, while Singapore Power International has ownership interests in Jemena, United Energy and ActewAGLand SP Ausnet.

2.2 The scale of the network and its costs

In 2010-11, 305 generators fed the network of five jurisdictional transmission networks, 13 major distribution networks and 6 interconnectors. Collectively, state governments are significant asset holders in all of the above segments of electricity supply. The NEM accounts for around 90 per cent of the line length of the entire Australian electricity distribution system and provides energy to about the same share of Australian customers (Wessex Consulting 2010). The actual and forecast regulated network revenues over the (mostly five-year) regulatory periods still in force in early 2012 was $58 billion in June 2010 prices — $12 billion for transmission businesses and $46 billion for distribution businesses (AER 2011b, p. 60). The corresponding asset values for transmission and distribution network businesses in 2008 were, respectively, $14.2 billion and $ 44.1 billion in 2010 prices.

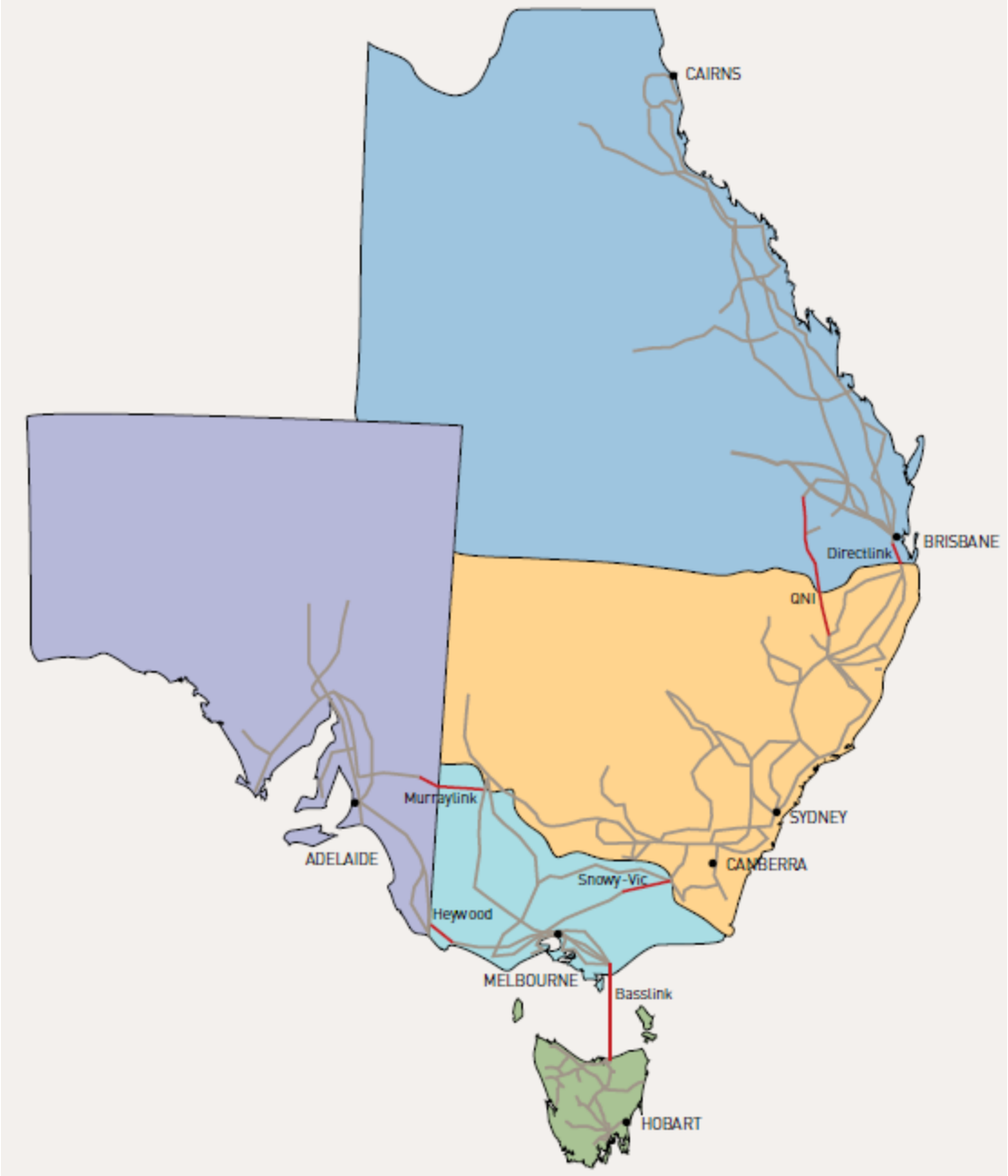
The NEM is one of the most geographically dispersed electricity networks in the world (figure 2.4).

The network comprises around 40 000 kilometres of high voltage transmission lines and 750 000 kilometres of lower voltage distribution networks (AER 2011b, pp. 53ff). There are also around 1500 kilometres of interconnectors that transmit power from one jurisdiction's electricity system to another, thus creating the 'national' market. To give a perspective on this, in the United Kingdom, there are around 25 000 kilometres of transmission lines and 800 000 kilometres of distribution lines serving a population of more than three times that of the NEM (UK Department of Energy and Climate Change 2011).

The total asset value of the NEM network was around $60 billion in 2010, with an expected five yearly investment of more than $40 billion (table 2.2).

The distribution network accounted for around 75 per cent of the total network assets and just over 80 per cent of the proposed new investment. This is why concerns about the efficiency of investment mainly relate to distribution networks. Interconnectors account for an estimated share of total network asset values of around 5 per cent. Transmission accounts for the residual network assets and investment.

Figure 2.4 **Transmission network infrastructure in the NEM**



Data source: AER (2009a, p. 126).

There is less information about other aspects of network businesses in the NEM because the AER concentrates on investment, assets, and regulatory revenues, rather than broader measures of the importance of the industry:[10]

10 The employment and outputs of the industry are important in gauging the potential economic impacts of reforms (section 2.7).

- Employment in network businesses was around 30 000 at 30 June 2011, but this is for all jurisdictions, not just the NEM (ESAA 2012, p. 10). Given that the NEM accounts for around 90 per cent of total customers (Wessex Consulting 2010), a reasonable employment estimate for NEM businesses is around 27 000. Somewhat dated Australian Bureau of Statistics (ABS) information on the industry for June 2007 suggests a number consistent with this (table 2.3). Average annual employee benefits are estimated to be around $128 000 per person in 2010-11 (based on adding wage inflation rates to the data from table 2.3).[11]
- Value added is estimated to be around $10.7 billion in 2010-11.[12]

Table 2.2 **Assets and investment in the NEM**

	Asset value 2010 (billion)	*Estimated investment in 2010*	*Investment rate (investment to assets)*	*Share of total assets*	*Share of total invest.*	*Segment's contribution to electricity price 2010-11*[e]
	$ billion	$ billion	%	%	%	%
Generation[a]	40.0	1.2	3.1	40.7	12.6	32.2
Transmission and interconnectors[b]	14.2	1.5	10.4	14.5	15.3	7.7
Distribution[c]	44.1	7.0	15.9	44.8	72.1	38.5
Total for above components[d]	98.3	9.7	9.9	100.0	100.0	78.3

[a] The asset values are for 2008 for the major power generators in the NEM, which account for nearly 100 per cent of installed capacity (NGF 2011, p. 1). The investment relates to 2010-11 for all generators in the NEM (AER 2011b, p. 44). [b] The estimates for investment are one fifth of the investment for the five yearly regulatory period. The estimates also exclude any investment by Directlink, Murraylink and Basslink. However, these interconnectors amounted to only around 8 per cent of the total asset base for all transmission and interconnector assets. That, and the fact that it is known that little investment has occurred in interconnectors, suggests that the estimates will be close to its correct magnitude. [c] The estimates for investment are one fifth of the investment shown for the five yearly regulatory period. [d] The data exclude other cost contributors to electricity prices, such as feed-in tariffs, RET subsidies and, most importantly, retail costs. The Commission could not find data on assets and investment for the retail segment of the market. However, this segment mainly comprises operating expenses, rather than capital investments. The overall contribution of the retail segment to electricity bills is about 10 per cent, so the asset share is likely to be much smaller than this. [e] These values are estimated as each segment's share of the Australia-wide price per KWh. The three cost sources do not add to 100 per cent because some other cost influences, such as retailing, are excluded. The generation share is estimated as the wholesale share.

11 The wage inflation rate was calculated as the weighted average of private and public of the growth rates in labour earnings for the electricity, gas, water and waste services industry (ABS 2012a, *Labour Price Index, Australia 2012*, Cat. No. 6345.0)

12 Estimated by applying the 2006-07 network service share of the value-added of the electricity, gas, water and waste services (EGWWS) industry to EGWWS value added in 2010-11 (from the ABS National Accounts), and then multiplying by 0.9 to remove non-NEM regions.

Table 2.3 **The significance of electricity networks**

2006-07, Australia-wide, current prices[a]

	Unit	*Generation*	*Transmission*	*Distribution*	*Retail*	*Electricity supply*
Employment end June	No.	9 487	**2 572**	**27 223**	4 620	43 902
Labour costs	$m	1 074	**307**	**2 914**	358	4 653
Sales & service income	$m	10 776	**2 180**	**13 506**	13 053	39 516
Value added	$m	5 075	**1 595**	**6 857**	1 036	14 564
Gross fixed capital formation (GFCE)	$m	2 662	**1 175**	**4 371**	321	8 528
Employee benefits per worker	$	113 208	**119 362**	**107 042**	77 489	105 986
GFCE share of value added	%	52.5	**73.7**	**63.7**	31.0	58.6
Industry value added per person employed	$m	534 943	**620 140**	**251 883**	224 242	331 739
Profit margin	%	13.6	**20.7**	**22.2**	1.2	12.8

a The full definitions of these terms are in the ABS publication below (pp. 37–47) and have not been reproduced. Labour costs are the full cost of employment (of which of around 90 per cent are wages and salaries). Value added represents the value added by an industry to the intermediate inputs used by the industry. Gross fixed capital formation is measured by the total value of a producer's acquisitions, less disposals, of fixed assets during the reference period (and so is not equivalent to investment in new capital). The profit margin is the percentage ratio of operating profit before tax to sales and service income.

Source: ABS (2008), *Electricity, Gas, Water and Waste Services, Australia, 2006-07*, Cat. No. 8226.0.

2.3 The nature of demand

Power consumption has been falling in recent years.[13] The ESAA estimates that consumption per customer fell by around 2.5 per cent in both 2010-11 and 2009-10. Indeed, even total consumption fell in these two years despite rising population and

[13] There are anomalies between the ESAA's (lowest), Bureau of Resources and Energy Economics' (highest) and the AER's (the middle) measures of electricity consumption. The AER's measure appears to relate to supply, which must be greater than actual consumption. The ESAA's data relate directly to consumption by various customers types and likely to be the better measure. Either way, the AER's data also suggest falling demand. AEMO's data (2012a) also shows an estimated decline in customer sales of around 2.4 per cent in 2011-12, but rising sales by 2013-14.

household formation. (The implication is that, all other things being equal, unit prices must rise to cover the high fixed costs of network infrastructure.)

In contrast to average demand, peak demand to average demand has generally been rising over time, reflecting the increasing penetration of air conditioning and the value people place on cooling during hot days (Topp and Kulys 2012, p. 42). This is a significant determinant of increased investment because networks must be built for peak use.[14]

There were around 9.1 million electricity customers in 2010-11, up by around 1 per cent from the previous year (table 3.2 in ESAA 2012). While around 90 per cent of customers are residential (some 8.1 million), these account for about 30 per cent of total consumption.

The importance to network businesses of the *demand* by various industries is quite different from the importance to other industries of the *supply* of network services.[15]

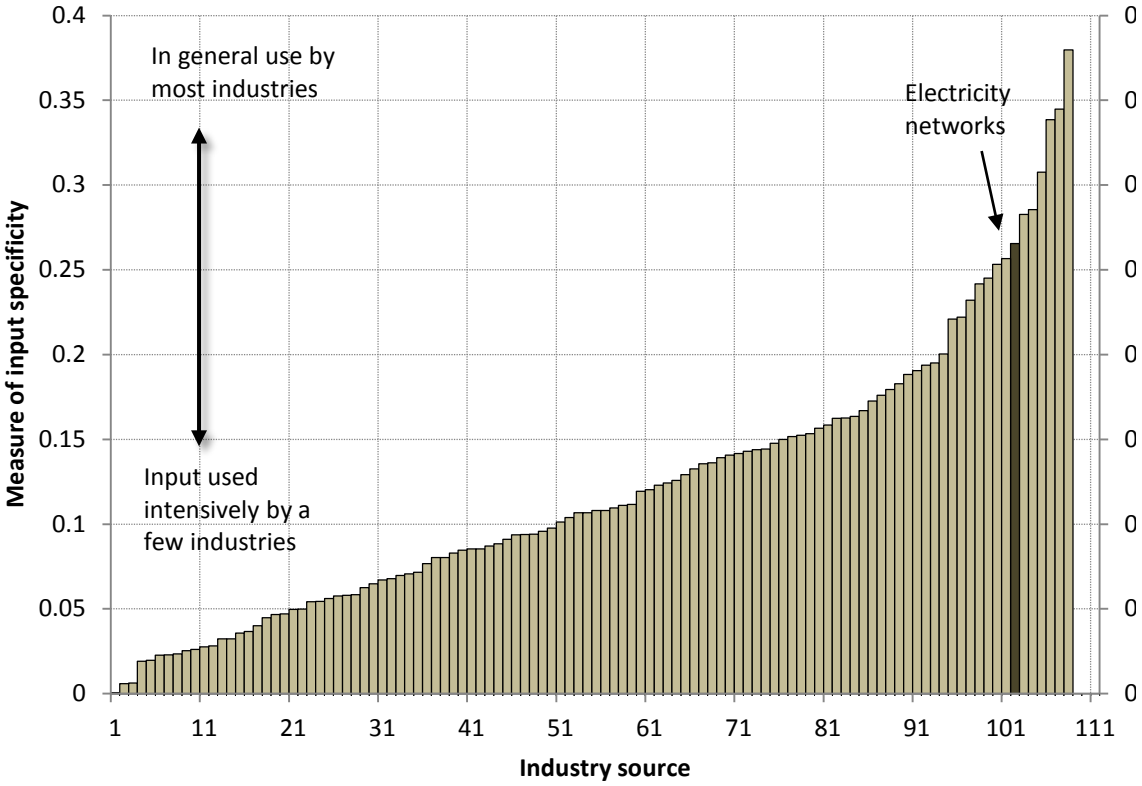
As far as the:

- former is concerned, network businesses have a wide customer base, although some industries, such as non-ferrous metal manufacturing and non-ferrous mining are particularly important revenue sources
- latter is concerned, of all industries that supply inputs to other industries, network services are characterised by close to the most uniform pattern of use (figure 2.5). Network services account for around 1–1.5 per cent of the value of inputs for the bulk of industries, although they are more important inputs for a few industries, such as ceramics and glass manufacturing (figure 2.6).

[14] Critical peak demand use has also declined in recent years — mostly due to milder weather — but is forecast to rise again (AEMO 2012a).

[15] For example, an industry might be highly dependent on electricity as an input, but have low overall output and low consumption of electricity, and consequently, provide little revenue to network businesses.

Figure 2.5 **Network services are general-use inputs**
2007-08[a]



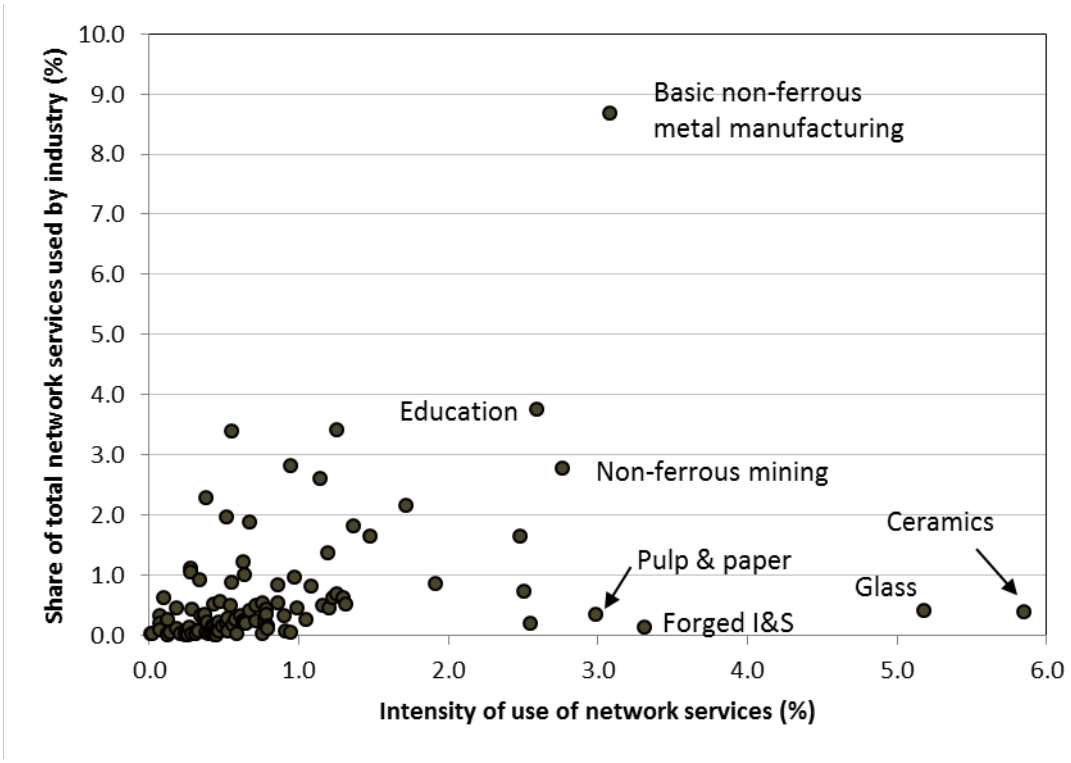
a The measure of specificity is calculated as follows. Let there be N industries. Define an input share (α) each industry in the total intermediate inputs (TotalUse) of each other industry:

$$\alpha_{jk} = \text{Input}_j / \text{TotalUse}_k \quad \text{for } j,k \in (1 \ldots N)$$

For any given industry (m) in the group 1 to N, there will be a vector of alpha values ($\mathbf{V_m}$) representing the importance of that industry as an input into other industries (α_{m1}, α_{m2}, α_{m3}, … α_{mN}). Calculate the ratio (R_m) of 20th and 80th percentiles of $\mathbf{V}_m$. Were a given input industry to account for one per cent of the total intermediate use of each other industry, then R_m =1. That means that industry m would be a general-use input. In contrast were R_m to be small then it implies that many industries make little use of that input and some a large amount — a high level of specificity. The data show that electricity network services are a general-use input (though typically a small share of each industry's total inputs – as shown in figure 2.6). Indeed, it is close to being the most general-use input among the large group of industries covered by the ABS input-output tables.

Data source: ABS (2012b), *Australian National Accounts: Input-Output Tables — Electronic Publication, 2007-08, Final*, Cat. No. 5209.0.55.001.

Figure 2.6 **Network services are a small share of inputs for most businesses, 2007-08**[a]



[a] Based on table 5, industry by industry flow matrix with direct allocation of imports (so that the table relates to domestically produced network services only. The shares relate to intermediate inputs into industries. The horizontal axis shows that network services are a relatively small share of total intermediate inputs of most industries. The vertical axis shows that, with one exception — non-ferrous metal manufacturing — networks rely on a wide range of industries for their revenue.

Data source: ABS (2012b), *Australian National Accounts: Input-Output Tables — Electronic Publication, 2007-08, Final*, Cat. No. 5209.0.55.001.

The implication of this pattern of use is that any individual business user has relatively little capacity to negotiate from a position of power with network businesses. However, the Major Energy Users (sub. 11) and the Energy Users Association (sub. 24) have nevertheless been able to act as stakeholders in requesting Rule changes and in representation during the regulatory process. In comparison, in the case of another regulated industry, airports, the number of direct users is small, and there is a much greater capability for negotiated arrangements. An issue in this inquiry is whether network customers could play a larger role in determinations, drawing on the information of benchmarking, and with resort to the regulatory powers of the AER as the 'stick'. Given the fragmented customer base, achieving that outcome requires a policy stimulus (chapter 21). The other implication of the pattern of use is that network businesses probably have little genuine capacity to 'hold-up' the investments of their customers — an issue relevant to the rationale for, and design of, the regulations (chapter 3 and appendix B).

Another facet of demand is its responsiveness to prices, which is relevant to the economic efficiency of addressing any network inefficiencies. Demand is not very responsive to prices in the short run, with a 10 per cent increase in prices likely to reduce electricity demand by somewhere between 2 and 4 per cent. The reduction is significantly greater — somewhere between 5 and 7 per cent — over the long run (Fan and Hyndman 2010, p. 8; Langmore and Duffy 2004). Consequently, some of the recent falls in electricity demand may reflect the impacts of the large price increases described in section 2.4. There is also significantly greater responsiveness to time-based tariffs, which shift demand from one period to another, rather than necessarily reducing daily demand by much.

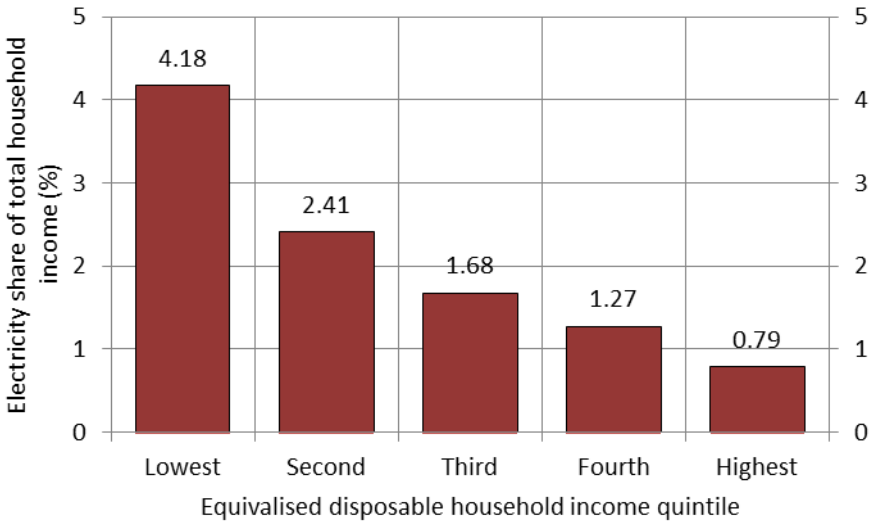
The responsiveness of demand to income is important for considering the distributional outcomes of any price reductions from reforms of network regulation. It appears that levels of electricity consumption are not very sensitive to income compared with most other goods and services. Consequently, the share of income spent on energy use falls significantly as household income rises.

Domestic energy use accounts for more than 4 per cent of household income for the lowest quintile under 1 per cent for the highest quintile (figure 2.7), or a ratio between the two of around 5.3 to 1. Other analysis suggests that this ratio is the third highest among the 35 broad commodity groups in the ABS Household Expenditure Survey — suggesting the inherently 'essential' nature of energy. More disaggregated analysis by the Independent Pricing and Regulatory Tribunal (IPART) for the Sydney region reveals that electricity spending can be as high as 14 per cent of income for the poorest households.[16] This income pattern of consumption is one of the reasons why concerns about network efficiency and their flow-on price effects have been given such prominence.

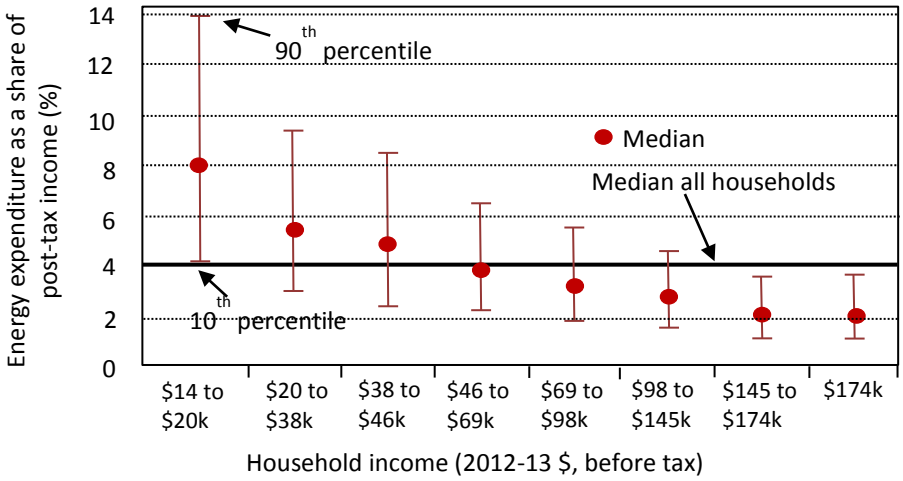
16 Nevertheless, while lower income households reveal that they have little capacity to substitute away from electricity, there is some (weak) evidence that they are more willing to face power interruptions (chapter 14).

Figure 2.7 **Lower-income households are hit harder by rising prices**

Australia 2009-10[a]



Sydney and surrounding regions, 2012-13[b]



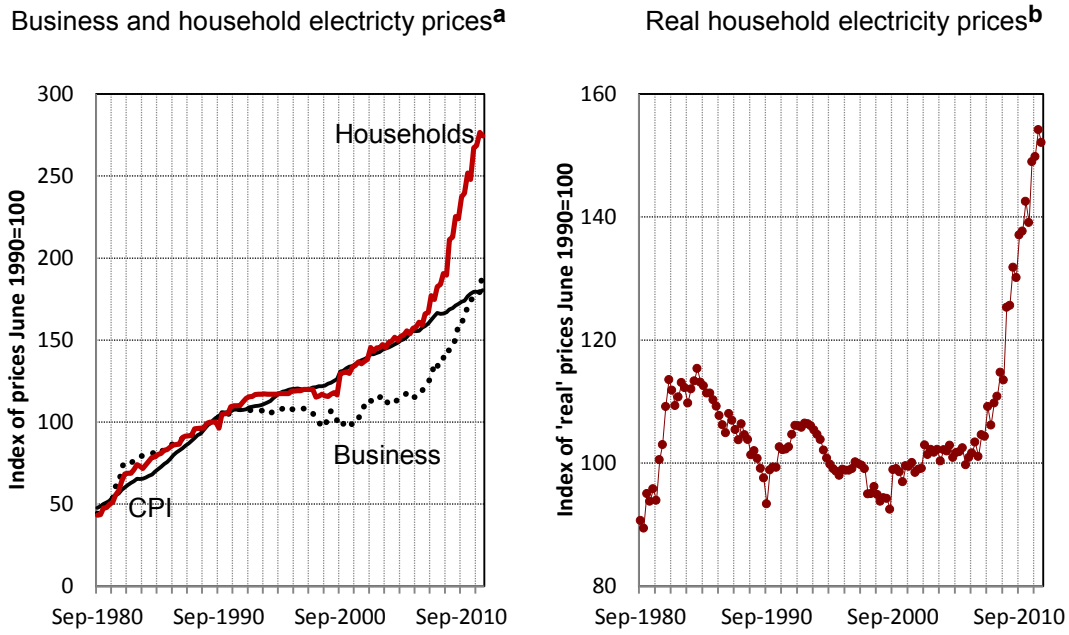
[a] Equivalised income quintiles take account of household size and composition in determining the values of income and spending in each quintile (ABS 2011b, p. 46ff). The ABS publishes aggregate household energy use (non-transport) on an equivalised income basis, but does not do so for domestic electricity use alone. However, both measures of energy use are available for non-equivalised household income quintiles, and these data have been used to estimate electricity usage on an equivalised basis. Note that the data for quintiles are averages. Many households in each group will be spending a greater (or lesser) share of their incomes than those shown. Higher than average spending shares are particularly relevant for the lowest income quintile. [b] Households have a distribution of spending from high to low. Percentiles measure the spending at various points in that distribution. For the lowest income group ($14 000 to $20 000), 10 per cent of households have a spending level below around 4 per cent of their household income (the 10th percentile), while 10 per cent of households in this income group have spending above 14 per cent of their income (the 90th percentile).

Data source: ABS (2011b); *Household Expenditure Survey, Australia 2009-10*, Detailed Tables and Summary of Results, Cat. No. 6530.0, September and IPART (2012a, p. 13).

2.4 Prices have been rising

Concerns about rapidly rising electricity prices have been a major source of concern to governments, businesses and the general community (figures 2.8 and 2.9). Until the mid-2000s, Australian retail electricity prices grew at around the same rate as economy-wide inflation, but then began to rise rapidly. From June 2007 to June 2012, Australian retail electricity prices rose by around 72.4 per cent, while general inflation increased by around 14.5 per cent, so that real electricity prices rose by around 50 per cent. (Box 2.1 explains what real prices mean.) Electricity prices facing businesses have also risen strongly, albeit by not the same degree.[17]

Figure 2.8 **Electricity prices**
September 1980 to June 2012



[a] Data are from September 1980 to June 2012, rebased so that June 1990 = 100. The data relate to all Australian electricity prices, not just those in the NEM, but the trends will be similar. [b] 'Real' prices are household prices divided by the CPI average for capital cities. The index shows how much electricity prices have increased above inflation.

Data sources: ABS (2012c), *Consumer Price Index, Australia, June 2011*, Cat. No. 6401.0; ABS (2012d), *Producer Price Indexes, Australia, June 2012*, Cat. No. 6427.0;

Electricity retail prices rose most strongly in Victoria (84 per cent) and New South Wales (79 per cent) over this period, more than 10 percentage points higher than any other jurisdiction in the NEM (figure 2.10). Future retail electricity prices in the

17 The reason for the lower price growth is uncertain, but may be due to re-balancing of tariffs.

NEM — at least partly locked in through regulatory agreements — are projected to increase by 29 per cent from 2010-11 to 2013-14.

Box 2.1 What are electricity prices?

It is important to clarify what household 'prices' denote. This report uses the standard ABS definitions. Unless otherwise stated, the price of electricity at any given time is the charge levied for power use by a household (or an index of this price), taking account of connection fees that are included in the price (ABS 2011c, p. 64). Both concessional and standard rates are included in the ABS approach. The ABS produces series only for capital cities and the Australian total is the weighted average of these series. The prices are the final retail prices, and incorporate wholesale costs (generation), network charges and retail margins, among some other costs.

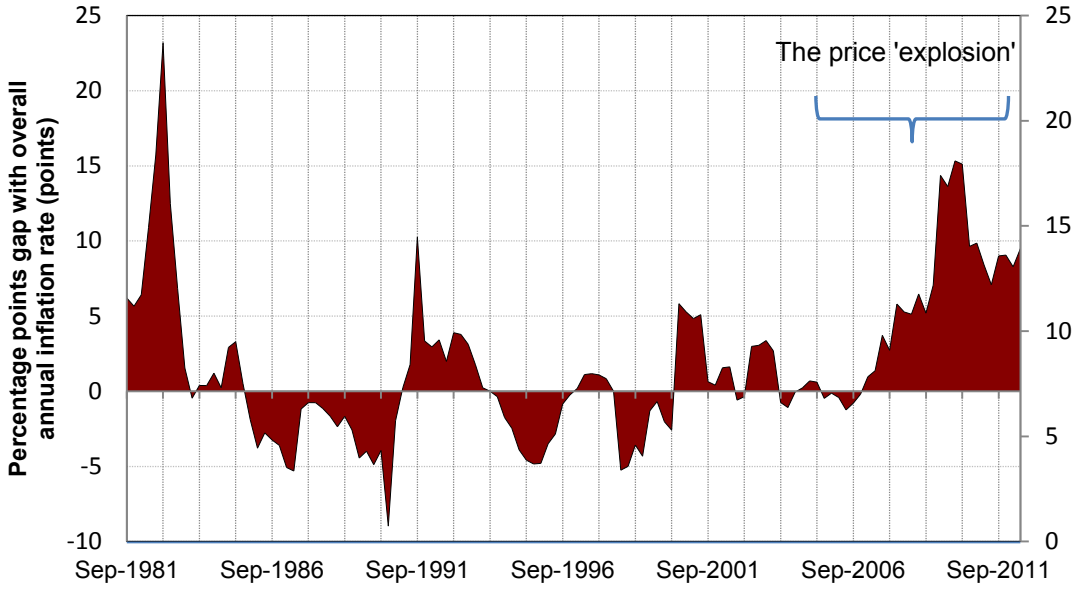
While statistical agencies avoid the nomenclature, the ratio of the electricity price index to the consumer price index is sometimes referred to as the 'real' price of electricity. This is a relative price measure, not a price per se. As it indicates how far electricity prices have shifted relative to prices in general, it identifies the price pressures unique to electricity. We explicitly indicate when we use relative or 'real' prices to distinguish them from the conventional meaning of prices. Note that where the percentage price increase between period t and t+n is π_e and the inflation rate over the same period is π_c, then the relative price change is $(\pi_e-\pi_c)/(1+\pi_c)$. Given this complexity, it is sometimes better to give π_e and π_c as separate (or at least as complementary) measures, especially in cases where real prices may be hard to interpret. For example, when comparing price movements *between* states, real price differences will reflect both changes in electricity prices in different states and changes in their separate CPIs. Similarly, a real producer electricity price might use an average business input price index as the denominator, which may be quite different from the CPI.

Ergon Energy pointed out some problems in interpreting retail electricity prices (sub. 8, p. 12), though these concerns are not likely to affect the broad patterns identified in the ABS data.

Source: ABS (2011c), *Consumer Price Index: Concepts, Sources and Methods, Australia*, Information Paper, Cat. No. 6461.0.

Figure 2.9 **The price explosion**

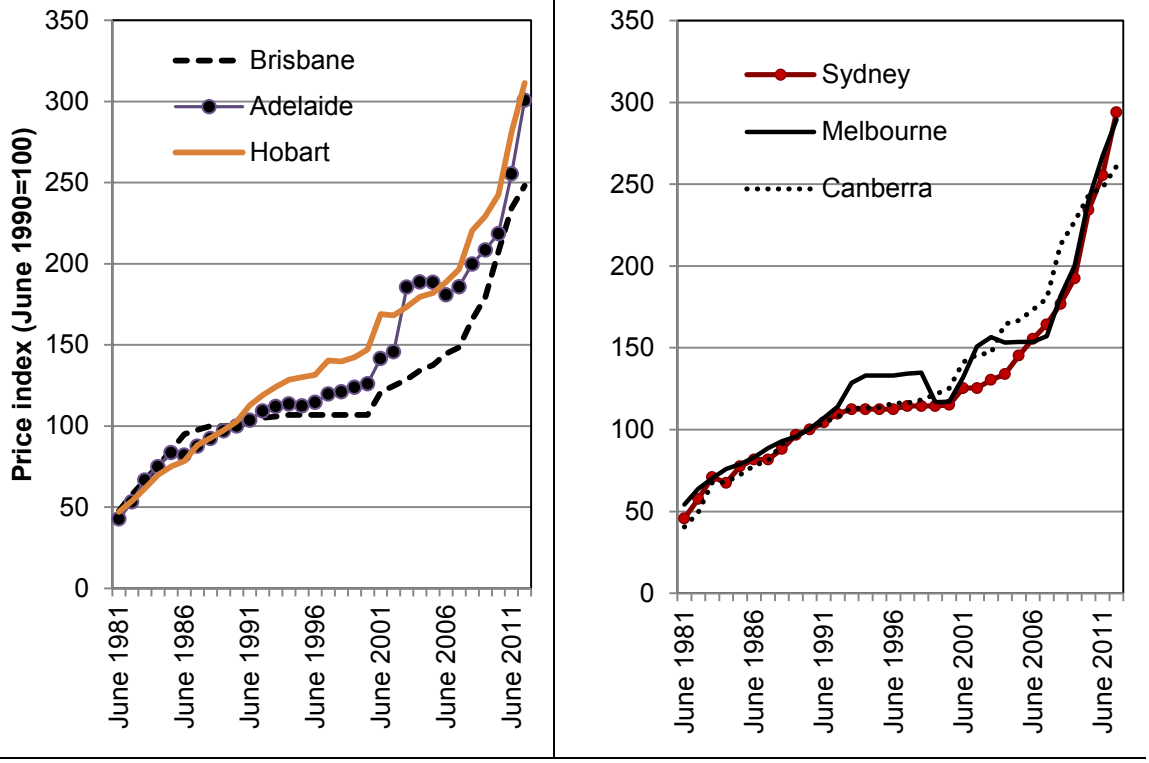
Annual growth rates (September 1981 to June 2012)



Data source: Figure 2.8.

Figure 2.10 **Relative residential electricity prices by NEM jurisdiction**

June 1981 to June 2012



Data source: ABS (2012c), *Consumer Price Index, Australia, June 2011*, Cat. No. 6401.0.

Growth rates in retail electricity prices accelerated in 2007 for Melbourne, Brisbane, Hobart and Canberra, 2008 for Sydney and in 2010 for Adelaide. In all but the last case, the regulatory determinations in force had been authorised by state-based regulators,[18] not the AER (and therefore were not encumbered by any unique flaws in chapter 6 of the Rules). While the Rules may have contributed to recent and forthcoming electricity prices, the price growth that preceded the new regulatory arrangements must originate from other sources.

Community concerns about electricity prices have been accentuated by their coincidence with similarly large increases in the costs of other regulated essential services — water and sewerage (69 per cent from June 2007 to June 2012) and gas and other fuels (45 per cent over the same period).

Many people are unaware that the costs of generating power are not the major contributor to their electricity bills. In 2010-11, the costs of network services represented between 31 and 55 per cent of the typical annual household electricity bill across the various jurisdictions in the NEM (and around 45 per cent for the entire NEM) (table 2.4; AEMC 2011a).[19] This represented a household cost for network services of between $350 to $700 per year.[20] In contrast, wholesale electricity prices from generators accounted for an average share of NEM-wide costs of around 35 per cent. The introduction of the carbon tax — which raises wholesale prices (generation costs) and retail margins — does not alter the relative importance of wholesale versus network costs to any great extent (figure 2.11).[21]

Apart from Victoria and the ACT, network costs have been the largest contributor to price increases since 2010 (AEMC 2011a; AER 2011b, p. 4-5, p. 20). For example, in New South Wales, network costs accounted for 80 per cent of the price increase in 2010-11 and 50 per cent in 2011-12. In contrast, in Victoria, changes to network costs had, at best, marginal impacts on electricity prices in 2011. The AEMC has forecast a similar pattern until 2013-14 (table 2.4).

18 This relates to distribution businesses (which account for the bulk of network costs), not transmission businesses. However, the Australian Competition and Consumer Commission (not the AER) had authorised most of the transmission determinations that were in force at the time that prices began to accelerate.

19 The AER (2011b, p. 110) derive a slightly different range of 41–51 per cent, but exclude Victoria.

20 This takes account of the varying typical power consumption patterns across jurisdictions.

21 With a range of 27–52 per cent across the NEM jurisdictions and an unweighted average of 43.3 per cent in 2013-14.

Table 2.4 **Projected network costs 2010-11 to 2013-14**

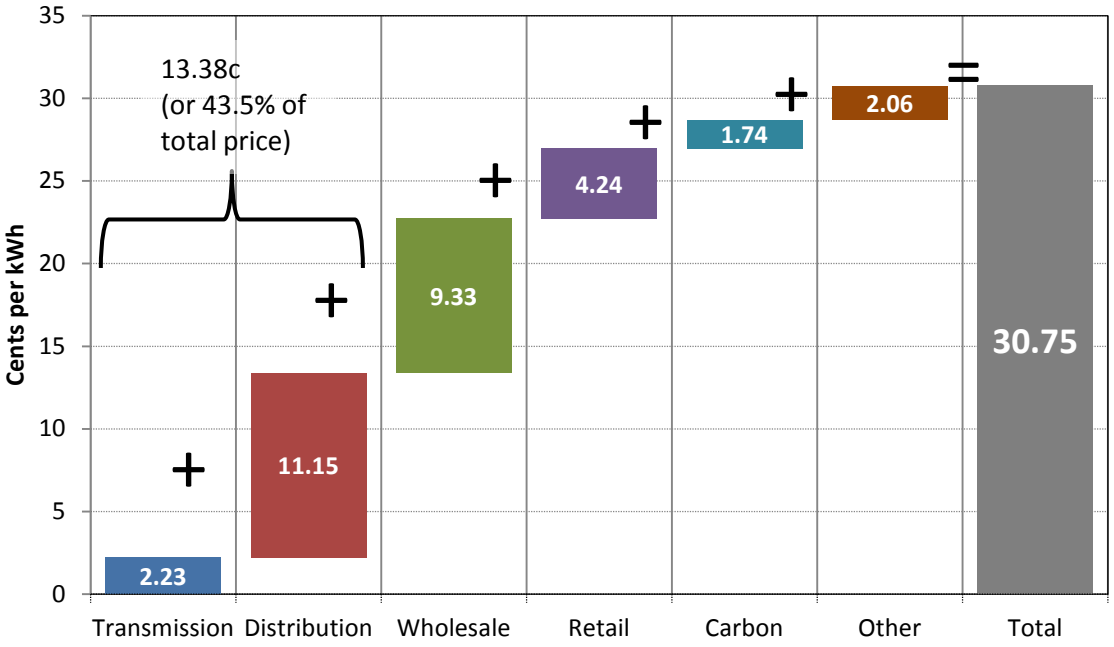
	Network costs			*Network share of total residential electricity costs[a]*		*Contribution to price increases from 2010-11 to 2013-14[b]*	
	2010-11	2013-14	Increase	2010-11	2013-14	Distribution	Transmission
	Cents/kWh		%	%	%	%	%
Qld	11.35	15.33	35.1	54.9	52.4	40.3	6.1
NSW	12.51	16.54	32.2	55.0	51.3	36.2	6.2
ACT	7.11	8.48	19.3	43.9	37.0	14.2	6.1
Vic	7.09	8.23	16.1	31.0	27.1	15.3	0.0
SA	10.67	15.06	41.1	44.5	46.2	40.3	10.8
Tas	9.94	11.91	19.8	47.9	45.9	22.5	15.4
WA[c]	7.87	11.99	52.4	35.7	38.4	34.2	10.4

a The cost shares in 2013-14 are affected by the introduction of the carbon tax, which raises wholesale electricity prices and the retail margin (but also involves some offsets). **b** The estimates are calculated as the change in the cost of power (in cents per kWh) attributable to transmission and distribution as a share of the total increase in the cost of power over the relevant period. **c** Electricity prices in Western Australia relate to the South West Interconnected System (SWIS). The prices in this state exclude the tariff equalisation contribution to areas outside the SWIS, as these represent transfer payments rather than cost-related prices.

Source: AEMC (2011a).

Figure 2.11 **Projected residential price cost components in 2013-14, Australia[a]**

Cents per kWh



a The carbon tax cost effect is calculated as the difference in the final retail price estimated by the AEMC with and without the carbon tax.

Data source: AEMC (2011a).

Transmission costs are far lower than distribution costs, and so their projected contribution to overall electricity price growth is muted. However, as noted by industrial businesses, the significance of transmission costs may be much greater for businesses close to the transmission supply point (Energy Consumers Group 2011, p. 9).

There are dramatic differences in the costs of network services in various jurisdictions. By 2013-14, the AEMC forecasts that total network costs in cents per kWh in Queensland, New South Wales and South Australia will be 86 per cent, 101 per cent and 83 per cent higher respectively than the costs in Victoria. Much of the debate about network performance rests on the degree to which these large gaps reflect excessive and inefficient costs or different operating conditions and capital vintages (chapter 6). Notably, the AEMC projections show that the disparities between network costs are likely to grow over time, instead of converging (unlike other costs, which are converging). Given that the physical environment of businesses do not change rapidly over time,[22] spatial differences in the topography and climatic conditions of network businesses cannot readily explain this divergence (figure 2.12).

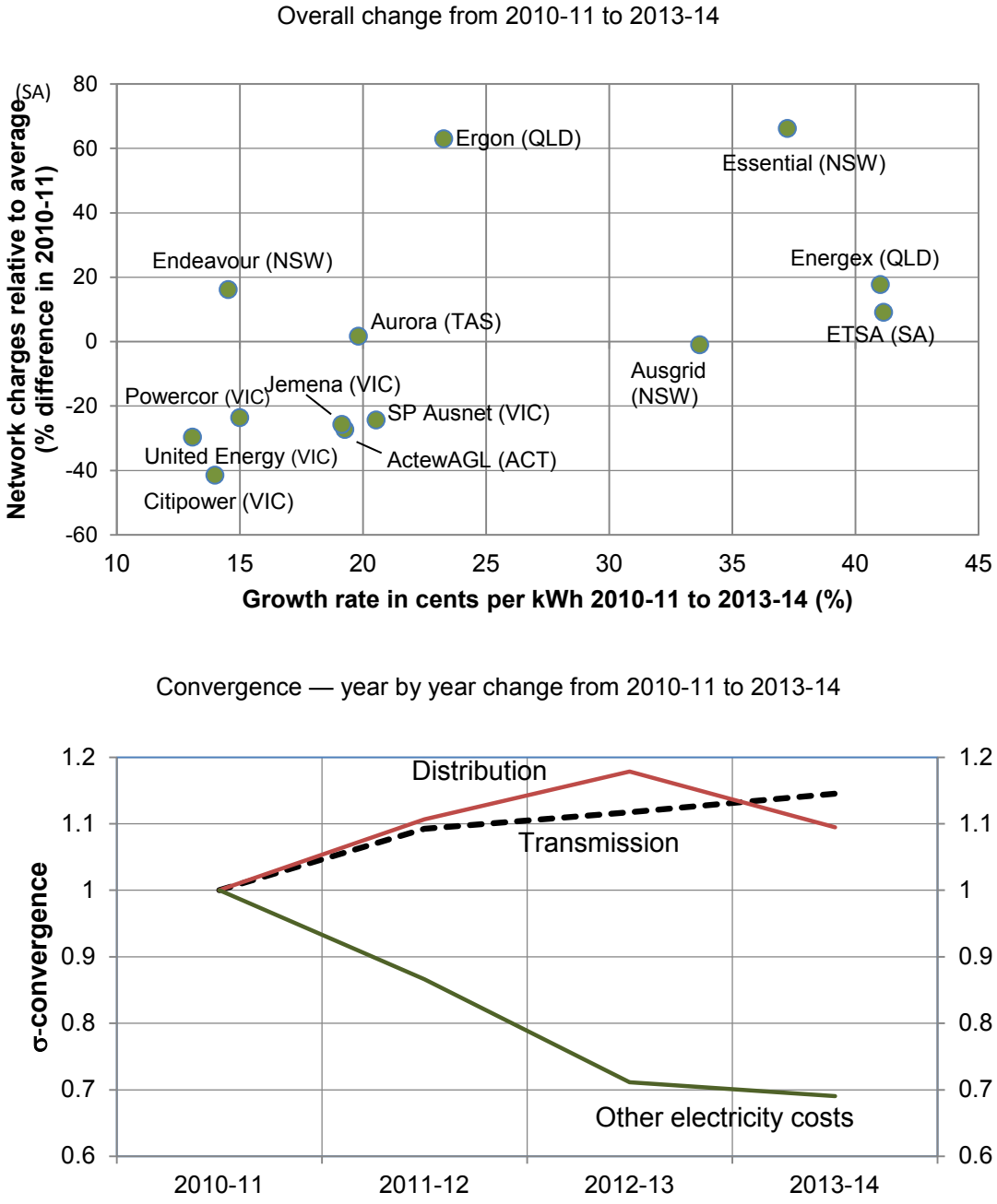
2.5 The proximate reasons for higher network charges

Some of the contributors to network price increases have reflected input cost increases, which are typically outside the control of either network businesses or government. For example, rising steel, copper and (to a lesser extent) aluminium prices have increased costs (AER 2009a, pp. 485ff; Plumb and Davis 2010; figure 2.13). Wage rates for public sector electricity, gas and water utilities have increased at a faster rate than wages in their private sector counterparts, and all industries (figure 2.13).

Since they are determined as part of the regulatory process, increases in the regulated weighted average cost of capital are also major determinants of regulated revenues, and of resulting prices (chapter 5).

[22] Peak demand in summer between 2012 and 2021 is projected to grow at different rates. The forecast growth rates are low for South Australia, New South Wales and Tasmania, and highest for Victoria and Queensland, (AEMO 2012a).

Figure 2.12 **Network costs differ between businesses and the gap is widening**[a]



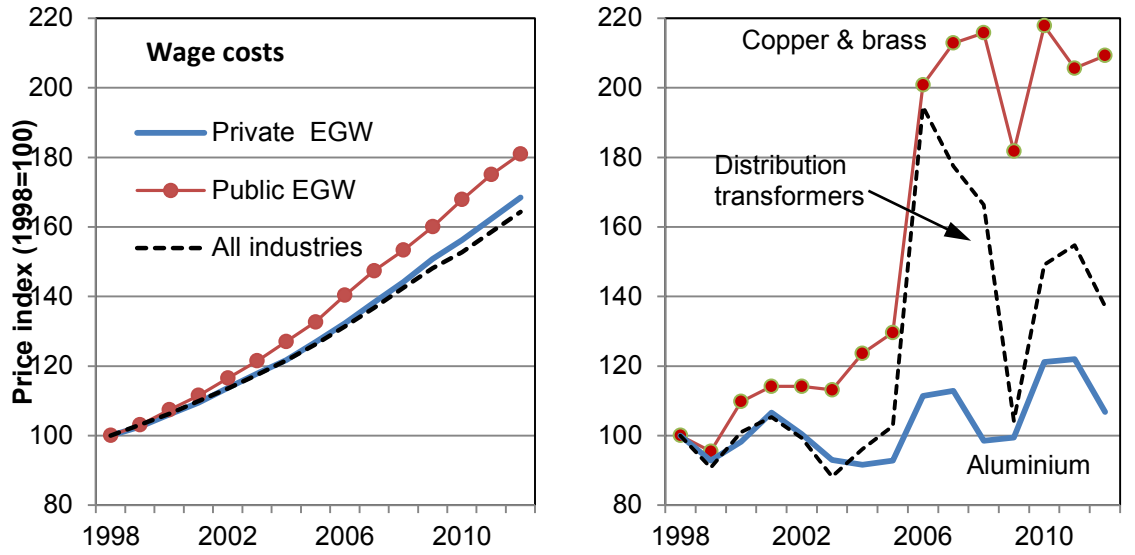
[a] Network costs are the sum of the transmission and distribution costs for each business. The top graph shows that businesses with costs well above the NEM average in 2010-11, tended to have faster forecast percentage growth rates in costs from 2010-11 to 2013-14. Given this depiction of the data can sometimes give biased estimates of the extent of convergence or divergence (Friedman 1992), measures of so-called σ-convergence rigorously test whether convergence is present or not. σ-convergence occurs when the coefficient of variation between states declines over time. In this case, the data reveals divergence.

$$\sigma - convergence = \left(\frac{var(R_{2013-14})/average(R_{2013-14})}{var(R_{2010-11})/average(R_{2010-11})}\right)$$

Data source: AEMC (2011a) and PC calculations.

Figure 2.13 **Input prices**

June 1998 to June 2012



Data sources: ABS (2012a), *Labour Price Index, Australia*, Cat. No. 6345.0; ABS (2012d), *Producer Price Indexes, Australia*, Cat. No. 6427.0.

Above all, lower productivity appears to have been a major pressure on network charges. In recent years, the stock of electricity infrastructure has risen rapidly and, unusually by historical experiences, labour inputs have risen. As output has not risen as rapidly as average inputs, measured industry efficiency has fallen, and with it, prices per unit of power have risen.

While it is less clear what has happened to the multifactor productivity (MFP) of network services specifically, most of the factors driving lower productivity in the electricity industry appear to relate to the network (Topp and Kulys 2012).[23] Evidence from IPART (2010) supports this, finding that in New South Wales there were more pronounced productivity reductions for network businesses than for generators.

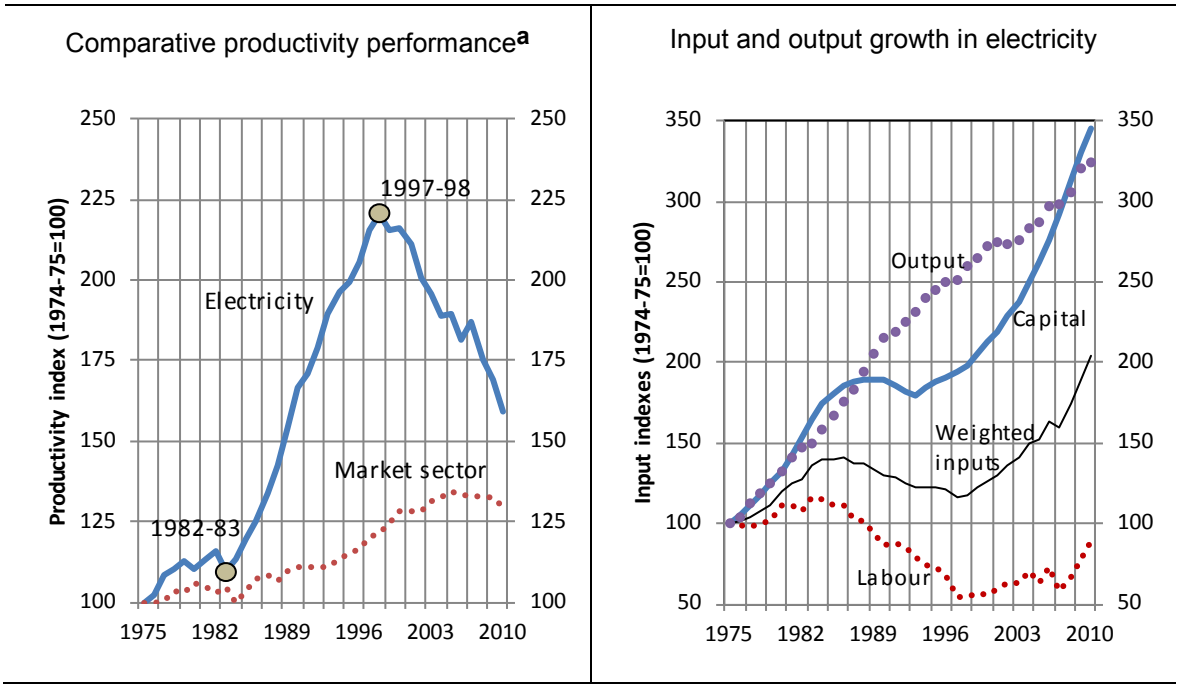
Topp and Kulys identify three phases of multifactor productivity growth in the electricity industry (figure 2.14):

- moderate growth phase from 1974-75 to 1985-86
- a rapid growth phase from 1985-86 to 1997-98

23 MFP measures the extent to which output growth cannot be explained by labour and capital inputs. Over the long-run, it measures greater efficiency and technical progress, while over the short-run it may reflect the business cycle or any other factor that leads to temporary underutilisation of capital or labour.

- a negative growth phase 1997-98 to 2009-10.

Figure 2.14 **Measured electricity sector productivity has been falling**
1974-75 to 2009-10



[a] Multifactor productivity estimates are increases in real output after taking account of changes in labour and capital inputs. The market sector includes all industries, with the exception of a few industries (public administration and defence), where reliable measures of productivity are difficult to calculate.

Data source: Topp and Kulys (2012).

Much of the negative growth rate appears to reflect capital growth without commensurate measured output growth. At face value, that suggests inefficiency. However, at least some of the growth in the capital stock reflects replacement capital for ageing assets, and new capital to meet the demand for greater reliability levels, growing peak demands, and requirements for greater undergrounding of lines (noting that underground lines are significantly more costly than overhead lines). Network businesses pointed to some of these pressures (for example, Ergon Energy sub. 8, p. 11). The ABS' output measures for electricity fail to take account of the value of customer reliability, the benefits of undergrounding or the additional value of capacity at peak times. Were these counted as output benefits, MFP growth would have been higher.

Nevertheless, the fact that some pressures have legitimately led to rising capital investment, and therefore a measured fall in productivity, does not necessarily mean that network businesses have performed as efficiently as they could. The regulator and many customers claim that regulatory flaws have led to premature and

inefficient investment. These investment patterns (and the possibility of addressing them through benchmarking) are the preoccupation of chapters 5 to 8.

Moreover, even though customers value reliability, it is not clear that many of the investments have actually increased reliability or, to the extent that they have, that the benefits to customers have outweighed the investment costs (and the associated price increases that these entail). Similarly, while rising peak to average demand requires network reinforcement, it is an open question whether other approaches — such as demand management — could have been used as a more efficient alternative. Accordingly, there is a potentially large difference between the *proximate* causes of rising network investment and the real underlying forces at work.

2.6 Reliability

The reliability of networks has many dimensions — such as the number of outages per customer, average interruption durations and the geographical reach of outages (chapter 14). Generally, transmission networks are very reliable due to their high level of redundancy and the rarity of events likely to trigger outages. Consequently, the most meaningful measure of network performance over short periods relate to distribution networks.

There are marked differences in reliability levels between states, with a persistent gap between that of Queensland distributors and those in other jurisdictions (figure 2.15), only some of which appears to reflect lower customer densities.[24]

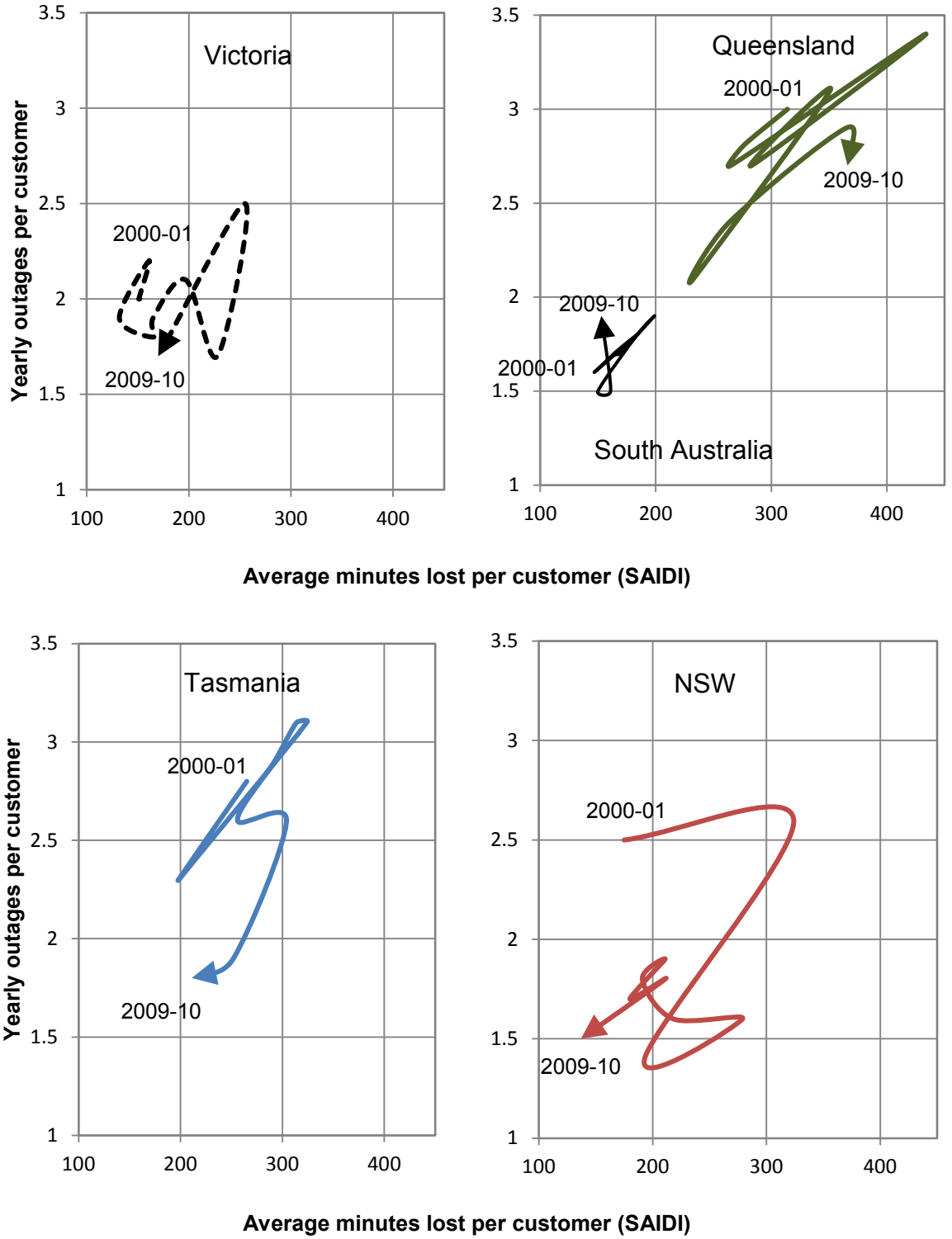
The AER has observed that the reliability levels, as measured by average annual outage durations[25] and the annual number of interruptions per customer[26] have been relatively stable over time. The Commission found only one statistically significant trend — an increase in average minutes of outages per customer of 10 minutes per year in Victoria.

24 Even when controlling for rural location, reliability tends to be lower for Queensland network businesses (AER 2008a, p. 162).

25 System Average Interruption Duration Index.

26 System Average Interruption Frequency Index.

Figure 2.15 **Reliability varies significantly**[a]



[a] The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control, although problems due to major weather events have been excluded. SAIDI denotes System Average Interruption Duration Index.

Data source: AER (2011b, p. 68).

While there is a positive relationship between annual interruption frequency and interruption duration, it is not a strong one (figure 2.15). Since, all things being equal, any reduction in interruption frequency should lead to reductions in average annual hours lost per customer, this implies that average durations of interruptions[27] are tending to rise as interruption rates fall. There are statistically significant (but small) trend increases in average durations per outage in Queensland, Victoria and Tasmania, whose cause is unknown.

Regardless, the reliability data shows that many of the shifts from year to year reflect random events — shown by the gyrating movements in figure 2.15. It is certainly not evident that the large increases in capital expenditure across the NEM have achieved greater reliability. That need not imply inefficient investment since it is possible that without such spending, reliability would have fallen (an issue where benchmarking analysis at the business and sub-regional level would be useful).

2.7 What is at stake?

As shown in tables 2.2 and 2.3 and figure 2.5, the electricity network industry commands a large amount of resources and provides services throughout the economy. That suggests potentially large benefits from reducing even small inefficiencies, let alone those of the magnitude suggested by some participants. Like unhappy families in Tolstoy's *Anna Karenina*, inefficiency can be manifested in many ways:

- Businesses may invest prematurely in what would ultimately be productive investment (the likely outcome of insufficient demand management or excessive reliability standards).
- Businesses may use existing capital inefficiently (lower capital productivity). For example, poor maintenance arrangements may require more redundancy than necessary.
- Businesses may make investments that are not required at all to produce output (the conventional definition of 'goldplating').
- Investment costs may be excessive due to poor project management.
- Labour may be in excess of what is required or poorly used (resulting in lower labour productivity).
- Physical investments and labour inputs may be at efficient levels and used efficiently, but may be priced excessively. This could arise if the weighted

27 This is the Customer Average Interruption Duration Index or the average restoration time.

average cost of capital is too high or if unions are able to negotiate higher wages (which appears to be true — figure 2.13 — especially for the state-owned corporations). High network prices lead to so-called allocative efficiency losses for customers (chapter 3). The structure of prices may also be inefficient if they are not cost-reflective (an issue particularly relevant to time-based charging — chapter 11).

The incorporation of benchmarking into incentive regulation (or even the publication of benchmarking results) attempts to eliminate such inefficiencies. However, the magnitude and timing of any such benefits depend on the nature of the policy reform and the source of the inefficiency.

Since most regulatory determinations have some years to go (table 2.5), at best, any reforms of incentive regulations would not have effects on the most costly part of the system (distribution) until after mid-2014 at the earliest. Reforms to incentive regulations may take some time to deliver benefits. This (and the period taken to roll out smart meters) also extends the timing of major demand management initiatives by some years (chapter 10).

Table 2.5 **Timing of regulatory determinations**

State	*Prior to AER role*	*AER determinations*
Distribution network businesses		
Queensland	1 July 2005 to 30 June 2010 (QCA)	1 July 2010 to 30 June 2015
NSW	1 July 2004 to 30 June 2009 (IPART)	1 July 2009 to 30 June 2014
Victoria	1 January 2006 to 31 December 2010 (ESCV)	1 Jan 2011 to 31 Dec 2015
South Australia	1 July 2005 to 30 June 2010 (ESCOSA)	1 July 2010 to 30 June 2015
Tasmania	1 July 2008 to 30 June 2012 (OTTER)	1 July 2012 to 30 June 2017
ACT	1 July 2004 to 30 June 2009 (ICRC)	1 July 2009 to 30 June 2014
Transmission network businesses		
Queensland	1 January 2002 to 30 June 2007 (ACCC)	1 July 2007 to 30 June 2012
NSW	1 July 2004 to 30 June 2009 (ACCC)	1 July 2009 to 30 June 2014
Victoria	1 January 2003 to 31 March 2008 (ACCC)	1 April 2008 to 31 March 2014
South Australia	1 January 2003 to 30 June 2008 (ACCC)	1 July 2008 to 30 June 2013
Tasmania	1 January 2004 to 30 June 2009 (ACCC)	1 July 2009 to 30 June 2014

Source: Various determinations by the AER and by state and territory regulators.

Even when the AER makes new regulatory determinations, it would not be possible to deploy existing excessive ('goldplated') capital elsewhere — these are sunk investments. The best that can be achieved is a lower future level of investment to avoid goldplating.

The removal of any excessive reliability standards could have more immediate efficiency effects (as could better use of the existing capital stock and improved project management), since these could defer or reduce some investments forecast under current regulatory determinations. Given incentive regulations, this would increase network profits, but not reduce prices until the next reset. However, higher profits are better than unnecessary investment. They permit greater investment elsewhere in the economy or can increase consumption. The value of deferred investment is approximately equivalent to the gain in net national income from such reform. An important and policy-relevant exception is that where the network business subject to new reliability standards is foreign-owned, the profits represent transfers abroad, and do not constitute welfare benefits to Australians. This is relevant to the process for privatising state-owned network businesses (chapter 7). If governments announced new reliability standards before privatisation, the short-term profits would be capitalised in the sale value, and still benefit Australians.

'Back-of-the-envelope' calculations suggest that deferred investment can yield substantial economic benefits. Based on relatively modest assumed deferral (of three years), the net present value of the benefits were nearly $8 billion over a 30 year period. Whether such savings can be realised depends on how far reliability standards are away from their optimal level.

There could also be large benefits on the employment side. Employable people are footloose in a flexible economy. This means that if there is a productivity improvement in one industry, people usually find jobs elsewhere at close to their former wages. In the case of electricity networks, employment is as geographically dispersed as are the wires and poles. Accordingly, the frictions in movements of employees sometimes associated with employment losses concentrated in a particular location would be less likely. Given estimated employment levels in network businesses, a 10 per cent improvement in labour productivity would release around 2500 workers to other industries, with annual economic benefits of around $300 million. Since these benefits would be sustained over future years, the net present value of the benefits would be substantially greater.

The above estimates of the economic benefits of higher labour and capital productivity are illustrative. They depend on assumptions about future growth in investment, capital and labour and use scenarios that may not be realistic. Nevertheless, one conclusion is robust — small improvements in the efficiency of electricity networks have large absolute benefits for Australians.

Any household consumption-side efficiency benefits from reform are likely to be much smaller as electricity demand is relatively inelastic (section 2.3) and because network infrastructure is only a share of total electricity retail costs. However, the

gains may be larger for globally footloose industrial businesses, which will tend to be more responsive to prices and in particular to their likely future trajectory (chapter 3). The consumer transfer benefits from reform would be more important, and as discussed in chapter 3, are still relevant in gauging the beneficial impacts of competition regulations.

General equilibrium effects

General equilibrium (GE) analysis takes account of the multiple linkages between industries (reflected in the importance of electricity networks to all other industries shown in figure 2.5), and of how price and productivity shocks cascade throughout an economy. GE benefits often exceed the benefits of reform revealed by partial equilibrium analysis (like that above). GE benefits could readily be between 20 and 30 per cent higher.

3 The rationale for regulation of electricity networks

Key points

- In any given geographical area, electricity networks are natural monopolies as it would be uneconomic for another business to duplicate the infrastructure.
- The theory and evidence about the behaviour of natural monopolies suggests that without strong regulation, network businesses could be expected to set excessively high prices and potentially provide too low a quality of services.
  - They would also face fewer incentives for internal efficiency and greater motivations for rent seeking to shore up their unregulated status.
- These resulting static and dynamic economic inefficiencies provide a compelling rationale for regulation of network businesses.
- Moreover, while not necessarily an economic inefficiency, high unregulated prices:
  - lead to potentially undesirable transfers from customers to businesses
  - would be regarded as unfair by many consumers.
- These provide further grounds for regulation, though they do not greatly assist the actual determination of the right price.
- Concerns about the impact of higher prices on particular customers are a less credible basis for competition regulation since their correction requires cross-subsidies between customers. Unless a special case can be made, such equity concerns should be addressed through other means.
- Recently, the importance of the above rationales for competition regulation has been questioned. Instead, it has been argued that the main goal of regulation is to prevent the monopoly business from holding customers to ransom once they have made sunk investments that use the inputs of the monopoly business. Were this true, it would discourage customer investment in the first place (the 'hold-up' problem).
- However, the market circumstances that would lead to the hold-up problem are mostly absent, markets have other solutions to the problem were it to occur, and regulators can create the same problem for the investments in the monopoly essential service (with even worse efficiency and distributional outcomes for customers).
  - The orthodox rationales for strong regulation of natural monopoly are sound.

The appropriate regulation of electricity networks depends on the features of those networks (section 3.1) and the problems that would arise were they to be unregulated (section 3.2). The fact that electricity networks have market power is not controversial, but the channels through which that power is wielded — a core issue for regulatory remedies, including the role of benchmarking — remains complex and contested (section 3.3). Indeed, most recently, there have been challenges to the conventional wisdom on why regulation is necessary. Drawing on a new theory, different policy approaches have been proposed (section 3.4 and 3.5). The rationales implied by the considerations above help frame the appropriate policy goals of the regulator (section 3.6).

3.1 The characteristics of electricity networks

Electricity networks have several distinctive characteristics that affect the desirability and nature of regulation (most especially economic regulation).

In each geographic segment, supply of electricity costs are minimised through supply by a single distributor or transmission business — or a 'natural monopoly'. This reflects some collective features of electricity networks, including the:

- very large fixed costs of the network (and low marginal operating costs)
- scarcity of easements in distribution networks (and the opposition by householders and local governments to any potential duplication)
- safety concerns for consumers and workers were there to be multiple wires (overhead or underground) owned by separate businesses
- need for the system to act as a coherent network, with appropriate frequency and voltage control
- need for power on demand, and the incapacity to store power efficiently, which restricts the use of many distributed energy options and requires a very reliable network built to peak demand
- advantages of having generators located close to cheap energy sources that may nevertheless be some distance away from end users
- millions of customers, most with very limited countervailing bargaining power (unlike, for example, airports with airlines).

As such, there is no genuine capacity for new entry by a rival in any given area, unlike electricity generation or retailing. For example, an urban street would not sensibly have two sets of power lines owned by different suppliers.[1]

In addition to its standard natural monopoly characteristics, there are special features of electricity networks that could lead to significant advantages to incumbents even where the networks expand to new geographical areas. For instance, to bring power to a new customer zone from generators already connected to the incumbent's transmission system, a potential transmission rival must either:

- build a new line all the way to the existing generators (a high fixed cost) or
- need access to the incumbent's network. As discussed in chapter 17, the high voltage inter-regional transmission lines (interconnectors) might feasibly provide contestability in some parts of transmission, since each new transmission line in an interconnected system can act as a substitute for other lines. However, there would need to be a regulated requirement for any-to-any connectivity, as in telecommunications, which without access requirements, the incumbent would not be obliged to provide. (In fact, in the absence of regulated technical standards, it might be justified in withholding access given the potential externalities posed by network effects.)

Even were the transmission businesses to negotiate a commercial agreement, non-cooperatively determined charges for transmission rights could lead to higher prices than for an integrated monopolist. This reflects that each party acting independently could add a mark-up on marginal cost whose overall impact would be higher than the mark-up chosen by a horizontally integrated transmission business — the 'double marginalisation problem' (Laffont and Tirole 2000, pp. 184ff). In the United States, this has actually materialised, with customers and suppliers facing double margins on charges as their power crossed a utility's corporate boundary (Massey 2007, p. 6).

The natural monopoly characteristics of networks could also allow a network business to foreclose supply upstream (generation) and downstream (retailing), so that vertical integration of these activities would occur. However, structural separation of most monopoly networks has occurred through privatisation, new entry and the creation of separate state-owned corporations in the contestable part of

[1] Though there may be 'underbuild' when distribution wires are strung under higher-voltage wires on a sub-transmission line.

the market,[2] so this particular risk has vanished. Nevertheless, there remain some concerns about:

- the integration of generators and retailers — 'gentailers'. Whether this is genuinely a problem is not considered in this inquiry
- the potential for common share ownership of generation and network businesses, (albeit in separated entities) to influence decision making.[3]

The above features of electricity networks need not eliminate the scope for some competition. The relevant market should not be defined as the technology for transporting power, but by the responsiveness of customers to increases in electricity prices, which in turn, will depend on the extent to which customers can choose alternatives. For example, gas already provides some competition as an energy source for cooking, and water and household heating.

In the future, standalone distributed generation — such as rooftop photovoltaic cells or small gas-powered generators — may provide some competition to the network. However, the prospect of widespread competition of this form is not imminent. Even where they do exist, distributed generators still typically link to the distribution network so that they can feed in excess power, and customers can access power if the generators fail or cannot meet peak capacity requirements (chapter 13). Accordingly, their network savings will more likely apply to transmission. At least for inter-regional transmission lines, pipelines that transport gas to generators, which then feed power into regional transmission networks, is a more realistic source of competition.

For the immediate future, it is likely that without regulation, electricity networks could exercise substantial and enduring market power. (In this respect, they are not like innovating businesses that create momentary rents that competing innovative rivals then bid away — as in many electronic products or drugs.)

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2 Aurora Energy in Tasmania is an exception, and remains vertically integrated. There are moves to change this.

3 Even though the Queensland and New South Wales Governments have structurally separated their network and other electricity businesses, they still own a significant share of generation capacity in their states (AER 2011b, p. 29). In a private situation, the Australian Competition and Consumer Commission would not approve (a transaction that led to) common shareholding of businesses that would be likely to 'substantially lessen competition' (increasing the ability to wield market power) in a market (s. 50 of the *Competition and Consumer Act 2010*). It is unclear whether common government ownership of generation and network assets would necessarily have such an effect.

3.2 Evidence about the costs of market power

The *a priori* case for at least some regulation of businesses with enduring monopoly power in key goods and services is so strong that, at least in advanced economies, governments typically regulate them. Therefore, it is hard to find much detailed evidence about the actual behaviour of such businesses under a counterfactual when that regulation is absent. Some of the most notable exceptions are distantly historical — such as the US Standard Oil Trust, US railroads in the 19th century, and salt monopolies in 17th century France — all of which engaged in the price gouging anticipated for monopolies.[4] Gas distribution in the United States was initially unregulated, until prices rose too high after the formation of a monopoly gas trust (Troesken 2006). Private water companies appear to have set very high prices and delivered dangerously low-quality water to US citizens in the late 19th century (Troesken 2006, pp. 274–5).

The main, and hardly unsurprising, lessons from unregulated monopolies wielding market power are that they charged high average prices and that they spent significant resources trying to maintain that power.[5] That provides little empirical guidance about the magnitude or source of welfare costs that might exist for an unregulated electricity network in contemporary Australia. It is likely that an unregulated essential service monopoly today would be far more sophisticated — for example, in its pricing strategies and in its bargaining with different groups of customers.

The problems in gathering evidence about the counterfactual have several implications.

Arguments about the nature and magnitude of the costs of the market power of electricity network businesses (and guidance on the best counteracting forms of regulation) will draw more strongly on theories and 'reasonable' assumptions than in many other areas of economics.

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4 There have been many ostensibly unregulated state-owned utilities, but they were often charged with social goals that meant they were, in effect, partly regulated. Moreover, they did not usually face the same incentives as private firms due to their affiliation with government, and were often less exposed to even the risk of competition due to statutory barriers to entry. In that sense, their conduct may not be representative of an unregulated private monopolist.

5 Monopoly per se does not *necessarily* confer significant market power. For example, there may be countervailing power from customers (Oxera 2012). Airlines and airports are one illustration. Moreover, a monopolist that exploits their market power for most customers may do so to a much lesser extent for a commercial customer that uses the monopolist's output as an input into the production of a good exposed to very competitive markets.

As a result, it is hard to rigorously test rival theories about the exact nature of the costs of natural monopoly, and consequently, the best type and benefits of regulation. The situation is akin to observing a patient's health after receiving a treatment, but with less information about their health status before treatment. There is, however, the possibility of testing competing theories based on internal consistency, empirical evidence about behavioural relationships that hold more generally (for example, that businesses with high fixed costs often use two-part tariffs for efficient recovery of those costs) and based on the observation of partly regulated monopolies and unregulated businesses with transient market power. It is also possible to test rival theories about the impact of alternative regulatory regimes on efficiency and prices (a form of benchmarking).

Given the magnitude of the potential economic and social effects of different degrees of regulation, it is critical to separate the wheat from the chaff, else the community could become the victim of the ingenuity of particularly persuasive theorists. The last 150 years of competition theory demonstrates that alternative theories often reach radically different policy conclusions about the appropriate reach of regulation (none in some cases, to complete regulatory oversight or public ownership in others). No theory has proved entirely satisfactory, and some have appeared to excuse anti-competitive conduct (Crew and Kleindorfer 2004; Melody 2003). As Melody put it acerbically:

> … the essential criteria around which public utility regulation has revolved are the reasonableness of prices and the universality of service coverage. It is on this skeleton regulatory framework that a little meat and an enormous amount of fat has been hung during the last century. (2003, p. 7)

Finally, there is enough uncertainty about the effects of natural monopoly to avoid expressing convictions that a single meta-theory explains it all. Regulators have to be mindful that not only do they have less information and engineering expertise than the businesses they regulate, but also face uncertainty about the degree to which they have succeeded in their endeavours.

3.3 The case for regulating monopolies

Putting aside foreclosure risks, the usual basis on which governments regulate natural monopolies are higher prices and lower output. In the case of electricity networks, lower output may take the form of reduced quality and not just less network capacity. There is no single adverse consequence from these outcomes. Over several hundred years, economists and legal experts have identified multiple channels by which these outcomes can reduce people's welfare.

(i) Consumer preferences are not fully and efficiently met

If a network business were to charge a price to consumers that exceeded the full cost to the business of transporting power, then customers forgo some consumption that was valuable to them, and that the business could have economically supplied. (A similar outcome might occur if the network business skimped on quality.) The immediate customers of a network business may often be other businesses. High electricity prices could have significant effects on their output and investment, especially if they compete on global markets. But the long-run effects are experienced by households.

(ii) Production inefficiencies

Unless it has perfect price discriminating capacity, monopolists produce less output than is efficient. The inputs that the business would have used to produce that forgone output would be allocated elsewhere in the economy, but to lower-value uses.

The inefficiencies resulting from (i) and (ii) are the most commonly cited conventional sources of welfare losses from monopoly power. These inefficiencies can be static or dynamic. For example, the latter would include adverse effects on investment or on the drive for innovation or cost minimisation by a customer or upstream supplier of an unregulated monopolist.

Since they are well understood, this chapter devotes little space to (i) and (ii), but brevity should not imply that they are not significant (especially once their long-run effects are considered).

(iii) 'X-inefficiency' or business underperformance

In theory, shareholder disciplines and the risk of takeovers (at least for private companies) seeking to maximise profits should drive cost minimisation regardless of weak competitive pressures on the business. However, there are several theoretical reasons, backed by empirical evidence, that suggest that low levels of competition weakens the internal incentives for cost minimisation and innovation — creating so-called x-inefficiency.[6] For example, employees and managers may (rationally) work less hard, knowing that shareholders find it hard to observe their

6 However, x-inefficiency is not all waste. A quiet life is valuable to those enjoying it, and to that extent, x-inefficiency is a transfer from shareholders to employees (Alchian and Kessell 1962). However, there may still be waste because many employees would prefer to take the rent as wages, but cannot do so because wages are observable to shareholders.

lack of effort (so-called 'principal-agent' problems) and that the business will still survive without strenuous effort because of the absence of competitors.

While the term x-inefficiency originated with Leibenstein (1966), the nexus between the absence of competition and managerial underperformance has been persistently observed since economics began as a discipline. Nearly 250 years ago, Adam Smith (1776) observed, 'monopoly … is a great enemy to good management', while 80 years ago Hicks (1935) argued that the 'best of all monopoly profits is a quiet life'. Australia's principal competition regulator, the Australian Competition and Consumer Commission (ACCC), has recently echoed this sentiment, observing that market power can be manifested as a 'lazy monopolist with a quiet life' (Pearson 2011, p. 4).

There is strong empirical evidence from 30 years of international studies that x-inefficiency is a major source of economic waste in industries protected from fierce competition — particularly essential services. These inefficiencies are potentially much larger than the allocative efficiency losses described in (i) and (ii).[7] There is a parallel literature in trade policy providing further empirical support for the debilitating efficiency effects of weaker competition (in this case arising from barriers to import competition).[8]

As an illustration of its potential importance, empirical research found x-inefficiency of around 20 per cent in the Australian electricity industry prior to microeconomic reform, though this may partly reflect state ownership of vertically integrated electricity businesses, as well as statutorily guaranteed market power (Whiteman 1998). Mountain and Littlechild (2010) and Mountain (2011) claim even more profound inefficiencies.

X-inefficiency is of central importance to this inquiry as its measurement is the key function of most benchmarking analysis. The regulator may use benchmarking results as one source of evidence about the acceptably efficient operation of business to help determine regulated prices or revenues. Incentive regulation is based on rewarding businesses using the performance of a leading practice firm close to (but not usually at) the efficient frontier as the benchmark.

7 As discussed by Perelman (2011) and documented by Frantz (2007) for many industries, De Witte and Marques (2010) for water, Brons et al. (2005) for urban transport, and a large number of studies of the electricity sector (described throughout this report).

8 See Panagariya (2002) for a survey.

(iv) Rent seeking

Given the monopoly 'rents' achieved through transfers from consumers to businesses, well-run monopolies have the potential to earn high rates of return on assets. This can prompt wasteful lobbying and other 'rent seeking' — a term coined by the World Bank Chief economist, Anne Kreuger — to preserve monopoly power.

In theory, rent seeking (and its protection) could dissipate all or, indeed some multiple, of the rents as unproductive activity, though in practice that is unlikely (Congleton et al. 2008). Certainly, academics and others have identified rent seeking in almost all areas of economic activity where governments, through statute or regulation, have the discretion to restrain or increase market power. This is one reason why excessive regulatory discretion can be inefficient. Concerns about such rents applies to areas as disparate as preferential trade agreements (Cutbush 2010), water (Goesch and Hanna 2002), taxi regulations (Moore and Balaker 2006), union market power (Connolly et al. 1986), import protection (Olsen 2005; Ville 2007) and pharmacy (Philipson 2003).

The desire to preserve rents can also lead to excessive political power to the monopoly business or other parties, such as unions, that may share the rents. For example, this was apparent in some unregulated railroad monopolies in 19th century United States. The 'Camden and Amboy' monopoly railroad acquired sufficient political power that the State of New Jersey became known across the United States as the 'State of Camden and Amboy' (Stein 2012). One executive of the railroad famously said 'he carried the State in his breeches pocket, and meant to keep it there' (Rutgers University Libraries 2011).

However, the regulation of natural monopolies does not eliminate rent seeking since the monopoly business and its customers have strong incentives to influence the regulator to re-cast the regulatory contract to their own advantage. Indeed, sometimes incumbent utilities have lobbied government for the creation of a statutory monopoly, arguing that the quid pro quo of economic regulation is the guarantee of insulation from competitive entry (a strategy used by the giant US telco, AT&T, in the early 20th century — Melody 2003). Nonetheless, to the extent that a regulator significantly reduces rents, the resources that competing parties are willing to use to secure the remaining prize are also diminished.

The relevance of rent seeking for competition policy is the need to have a credible commitment to long-run constraints on monopoly power (without excessive discretion). As for other major natural monopolies, in electricity networks this is best achieved through clear regulatory objectives and statutes, a politically

independent regulator (such as the Australian Energy Regulator or 'AER') and institutional arrangements that give customers sufficient visibility and negotiating power to counter the monopoly businesses (chapter 21). Biggar (2011b, pp. 18–19) and Littlechild (2009) have given particular emphasis to the latter. The Commission agrees with this emphasis.

(v) The distributional effects of consumer to business transfers

Consumers and regulators often raise distributional matters. However, they are much less straightforward than the above issues. Monopoly rents are transfers from consumers to those with a stake in the monopoly business (shareholders and those employees who are able to achieve the 'quiet' life or can negotiate higher wages). Even where the initial impacts of monopoly are higher prices for downstream business customers or lower prices for upstream suppliers, the costs are ultimately likely to be borne by households.

Such 'consumer-to-business' impacts *may* matter in several ways. Society may value consumer welfare more than the welfare of shareholders or the business's employees (Armstrong and Sappington 2006; Sims 2012a). That might occur because the shareholders that have benefited from the rents are foreign so that their welfare is not relevant to maximising the welfare of Australians. Or, it may be because, as a group, the relevant consumers facing higher prices have lower income than shareholders. That presupposes that the marginal benefit to lower-income consumers of an additional dollar is higher than for shareholders. While this appears to be a reasonable claim, there is significant debate about when that should be considered in policy analysis (PC 2011a, pp. 955–56).

Distributional issues raise questions of fact and careful interpretation:

- If foreign shareholders purchased the monopoly business at a price that already fully capitalised the rents, then the preceding owners acquired the rents, not foreigners (a point made by Posner 2001). In some cases — and this is true for all Australian electricity networks and many other businesses with market power in Australia — state and territory governments were the original owners. Accordingly, it is possible that citizens acquired the stream of any future rents as a lump sum from the asset sale at privatisation. (Whether that is true depends on whether the sale process effectively captured all rents.)
- Monopolies are often state-owned. If the monopolies wield market power, the transfers are from consumers to citizens generally (either through reduced taxes or additional services). Whether there are any adverse distributional outcomes

depends on judgments about the capacity of governments, through the political process, to make wise distributional decisions.

- While there may still be distributional effects, they may be mitigated by diversified share ownership. For example, superannuation funds, which hold many of the retirement savings of Australian workers, sometimes have significant holdings in businesses with market power. In theory, the implicit taxes that monopoly imposes on consumers may be less for lower income consumers (depending on how the monopoly business sets its tariffs). In that instance, it is possible that transfers from consumers to shareholders have distributional benefits. Whether that occurs is a question of empirics, not principle. Currently, Australian private electricity networks are largely foreign-owned.
- There is little question that society values some re-distribution of income from higher-income to low-income people — as revealed by the tax and transfer system, and by people's private voluntary re-distribution of resources. However, the overall level of re-distribution in a society depends on the cumulative effects of the myriad ways in which re-distribution occurs. There is a point after which people see further re-distribution as undesirable. Accordingly, without knowing this bigger picture, it is unclear whether any single policy with re-distributive impacts is optimal. This aggregate perspective is overlooked in populist views about the desirability of achieving re-distribution in every instance where a policy has income or wealth effects.

The policy implication of the latter point is that the desirability of different re-distributive policies depends on their relative efficiency costs. It is possible to be strongly in favour of re-distribution of income in a society, but to be doggedly opposed on efficiency grounds to a particular policy that attempts to achieve that.

A possible argument for curbing any re-distributive effects of unregulated monopoly is that passing monopoly rents back to consumers resembles the outcomes of an efficient rent tax (Armstrong and Sappington 2006; and more broadly, Laffont 2005).[9] *If* correctly calibrated so as not to take too much from the monopolist, rent taxes should not raise relative prices or reduce production and investment incentives.

In achieving a desirable level of re-distribution in an economy, rent taxes could displace other inefficient taxes. Another way of looking at this is to imagine the political calls for greater family transfer payments, higher pensions and allowances,

9 This is subject to the proviso that the rents are not the outcomes of innovation or risky investments. Taxing such 'rents' would reduce incentives for risk-taking. That proviso is not likely to hold for standard investments in electricity networks.

and more utility assistance to relieve cost-of-living pressures were essential services to be priced at monopoly levels. Any such fiscal measures would involve new taxes to fund these outlays, with their associated inefficiencies. The excess marginal burden of taxes vary considerably,[10] but the most commonly applied taxes for gathering new revenue are income taxes. The accompanying technical paper to the Henry Tax Review found that labour income taxes, payroll taxes and corporate income taxes had marginal excess burdens of 24, 41 and 40 per cent respectively, while municipal rates (a rent tax) had a burden of 2 per cent (KPMG Econtech 2010, p. 44).

Consequently, there may be *efficiency* grounds for removing genuine rents through the regulation of natural monopolies and passing these back to customers as lower prices. The main drawback to this observation is that an implicit monopoly rent tax distributed in proportion to consumers' use of electricity is not equivalent to the outcome were the tax to be collected by government and then used to reduce debt or distortionary taxes. Nevertheless, there may be some efficiency benefits.

Regardless, addressing the conventional efficiency costs of monopoly will limit transfers from consumers to a monopoly business. As noted by Banks (2012, p. 12), the focus of National Competition Policy 'on promoting efficiency should not be seen as contrary to distributional goals.'

This is consistent with the National Electricity Objective (NEO) (as described in chapter 1), and particularly its emphasis on promoting 'efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity'. The NEO captures the central rationales for the regulation of monopoly businesses:

- efficient production by network businesses (static and dynamic)
- the efficient use of network services by customers (both households directly purchasing electricity and downstream business users that ultimately supply goods to customers)
- the necessity of ensuring efficient investment and other required expenditure needed to ensure long-term reliable supply.

[10] This measures the deadweight inefficiency costs as a share of each dollar of revenue that government raises. These costs arise because taxes affect decisions to invest and to work.

While it would also imply a preference for transfers to favour consumers where efficiency was not at stake, the NEO can be seen as fundamentally an efficiency objective.[11] As noted in the second reading speech for the Bill containing the NEO:

> The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised. (Second reading speech, *National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005*)

In their stage one interim report on the limited merits review regime, the panel (Yarrow et al. 2012b, p. 40) noted that the NEO has the advantage that it is both clear and emulates the outcomes of effectively competitive markets:

> The primacy of the long term interests of customers as an evaluation criterion, set out in the NEO and the NGO, gives the conduct of regulation the same focus as that of the supply-side of an effectively competitive market (how can we improve the consumer offering?). This is admirably clear, and avoids the confusions of multiple, conflicting objectives that have had adverse effects in jurisdictions such as Great Britain.

However, 'equity' is a problematic goal

A quite distinct distributional concern relates to the desirability or otherwise of reducing the costs of essential services for *specific* groups of consumers (regional dwellers, the old, the disadvantaged) financed through higher regulated charges for other customers, rather than financed by taxpayers generally. This is generally not a persuasive rationale for *competition* regulation. However, social concerns provide a rationale for other measures, such as hardship measures implemented by the businesses,[12] and sometimes financial assistance to particular groups.

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[11] The NEO suffers from some ambiguity — a point made in the Commission's analysis of the similar object clause in telecommunications competition regulation (Part XIC of the then Trade Practices Act); by the Energy Networks Association at the time of the Exposure Draft of the National Electricity Law (ENA 2004); and by Kerin (2012). However, these concerns are largely allayed given the guidance on the interpretation of the NEO in the second reading speech.

[12] These are measures adopted by the businesses that provide advice on energy use, and allow people to make instalment-based payments and deferred payments. They are not usually subsidies.

The reason such policies often accompany competition regulation is that:

- once a government regulates to address the market power of an essential service, it is easy to add other regulations with social (and environmental) goals
- a major reason that essential services have market power is because people cannot take or leave the services they offer — these are services critical to the everyday lives of all people. This characteristic also means that governments see it is as highly desirable that essential services are universally available and affordable for all people, regardless of their circumstances.

Whether such re-distributional policies should attach themselves to economic regulation depends on the desirability of such subsidies and on the relative efficiencies of the alternatives for financing them. Either way, they should not be an objective of the *competition* regulator. Budget-funded measures — such as utility allowances — have the advantage of transparency, clear parliamentary accountability and can use the same (targeted) eligibility criteria for other distributional policies to create a more coherent framework. In contrast, it can be hard to target price regulation for social welfare purposes (ERAA 2012, p. 4).

However, where social goals are achieved through regulatory means, they should be:

- targeted as best as possible and be as consistent as possible with budget-funded social welfare measures
- imposed as an explicit government directive so that it is clear who is responsible for the policy, but leaving some flexibility in how they should be met. The danger is that prescribing particular tariff arrangements to meet equity goals might undermine the main objectives of the regulator to set prices as efficiently as possible, with unintended long-run impacts for consumers generally
- be accountable and transparent, with full disclosure of their revenue equivalents, to avert another source of rent seeking.

This issue is relevant to this inquiry in that it may affect the appropriate 'efficiency' benchmarks in incentive regulations for businesses subject to extraneous social goals, and if poorly undertaken, could undermine some approaches for achieving network cost-savings through demand management (chapters 9 – 12).

(vi) Unfairness and 'injustice'

'Unfairness' has several dimensions. One is the distributional issue described above. The other concerns justice. For example, a common example of this aspect of fairness is the desirability of procedural fairness.

While little empirical work on this issue has been undertaken in Australia, the history of anti-trust regulation in the United States demonstrates that addressing unfairness is a key objective of utility regulation, with requirements for prices to be 'just and reasonable' (Beecher 2010). A large survey of the 207 state and federal utility regulators in 2001 found that the majority of commissioners considered fairness to be a central and often more important goal of utility regulation than efficiency (Jones and Mann 2001). Their view of unfairness extended beyond unreasonable prices, suggesting that the distribution of transfers were not the only consideration.

Likewise, competition law in the European Union gives strong weight to fairness. Abuse of a dominant position may consist in 'imposing unfair purchase or selling prices' (Akman and Garrod 2010).

In Australia, the *Competition and Consumer Act 2010* also places significant weight on prohibiting unfair practices, but does not refer explicitly to unfair prices. The competition and consumer regulator, the ACCC, has some (limited) capacity to oversight prices under Part VIIA of the Act. However, the ACCC has on occasions characterised its price monitoring role in terms of fairness:

> A price inquiry is conducted to determine whether buyers are getting a fair deal in the supply of goods and services. (2005, p. 8).

While unfairness is hard to define, people clearly identify it as an important feature of transactions. As two scholars in this field have noted:

> While the idea of fairness is elusive and perceptions differ, it clearly is a potent force in regulation, as indicated by the vehemence with which participants complain when they feel they have been treated unfairly. (Jones and Mann 2001, p. 153)
>
> … few persons give much attention to what is fair. But they know when they have been treated unfairly; perceived unfair treatment is what makes people shout, "I have been had (screwed, taken to the cleaners, etc.)! … the sense of unfair treatment typically comes from a perception that a contract, explicit or implicit, has been broken. (Zajac 1996, p. 117)

People regard transfers made under circumstances of duress or with significant unequal bargaining power as unjust, even if they do not entail significant distributional consequences. For example:

- Even if the perpetrator is disadvantaged and the victim not, most people would regard the theft of money as an undesirable and unfair form of re-distribution.
- Survey research has shown that most people regard the use of market power to raise prices as unfair, and that the degree to which prices are raised does not affect their judgment of unfairness by much (Kahneman et al. 1986, p. 735). The present chair of the ACCC (Sims 2012a) characterises public attitudes to

monopoly pricing in fairness terms (although he suggests that the best rationale for regulation lies elsewhere).

- In cases of costly litigation, people are sometimes willing to use significant resources to pursue matters where the economic losses are small, revealing the value they place on correcting what they perceive to be injustice and unfair treatment.
- In its inquiry into consumer policy, the Commission found people had an aversion to 'unfair' contracts that related to far more than their transfer effects.

The desire to enforce social norms against the unfairness or injustice that sometimes accompanies unequal bargaining provides an additional rationale for the regulation of natural monopolies wielding market power.

However, in practice, unfairness and injustice present difficult challenges for the price regulation of utilities, in contrast with the clear relevance of these concepts to misleading and deceptive conduct, anticompetitive actions, fraud and other forms of misconduct generally prohibited by, and redressed through, general trade practices and the common law. It is notable that the test of the misuse of market power in s. 46 of the *Competition and Consumer Act* requires that a business uses its power for an illegal purpose — not that it sets prices too high. Indeed, one of the targets of s. 46 is exactly the opposite — the strategic use by a business to strangle competitors by initially setting prices too low ('predatory' pricing).

The fact that some form of overpricing is widely seen as unfair indicates that some regulation may be warranted, but does not provide any analytical tools for calculating a 'fair' price. As with the issue of transfers to consumers, pursuing efficiency objectives will typically achieve the goal of fairness without any need for supplementary policies.

Moreover, judgments of fairness are highly subjective and depend on how a situation is framed (as shown in the many careful survey questions posed by Kahneman et al. 1986). Even where a monopoly business's prices are heavily regulated, many will still claim that the prices remain unfairly high (a point apparent in submissions made as part of regulatory determinations for electricity revenue and price caps).

Deadweight costs as an umbrella concept

The costs represented by (i) to (iv) are the standard 'textbook' economic efficiency losses of monopoly, with a parentage stretching back at least 50 years. Sometimes

these costs are categorised collectively as 'deadweight' costs.[13] Even (v) can be categorised as a deadweight cost, since its relief though regulation may also yield potentially substantial economic efficiencies.[14]

There is little evidence about the magnitude of the above costs were electricity networks to be unregulated. However, some of the important aspects of the story are:

- Electricity is an 'essential' service (a basic service that few households can do without).
- Electricity is used by every business and government (chapter 2). Any monopoly price effects cascade throughout the economy, before being ultimately borne by households (domestic and foreign). Accordingly, the price of a soft drink to the consumer will, among other things, reflect the impacts of excess electricity prices on the glass used to manufacture the bottle, the manufacturing process used to produce the drink and bottle it, the cost of power to make the bitumen and concrete for the roads that transport the drink, and for the power costs of wholesalers and retailers.
- The distortionary impacts of monopolies depends on the extent to which, for the various sub groups of customers, demand responds to higher prices ('demand elasticities). The existing evidence suggests relatively low elasticities of electricity demand for households (Fan and Hyndman 2010). In part, this is because it is an essential service. Since conventional deadweight losses are a function of such demand elasticities, that suggests relatively small consumption-side deadweight losses. However, the existing demand studies relate to an industry that is already highly regulated. It is feasible that demand elasticities would be greater were the monopoly unregulated, and so too, the degree of inefficiency.[15]

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13 Any basic textbook would categorise (i) and (ii) as deadweight costs. Moreover, many economists would argue that x-inefficiency and rent seeking also result in deadweight losses (for example, Dobson 1992; Johnston and Trembath 2005, p. 24; Crew and Kleindorfer 2004). Some argue that x-inefficiencies should not be *labelled* as deadweight costs because they arise from non-profit maximising behaviour by the business. However, x-inefficiency is perfectly consistent with profit maximising behaviour subject to principal-agent costs.

14 Some also argue that failure to address unfairness in (vi) is economically inefficient because fairness is a 'good' included in people's utility functions, with people willing to give up the consumption of other goods to increase it (such as in altruistic behaviour). This may be technically correct, but enumerating the inefficiency effects of unfairness is difficult, and as such, the point is conceptual rather than practical.

15 For example, if a demand curve is linear, an unrestrained monopolist will price up to the elastic portion of the demand curve.

- Even small increases in electricity prices can entail significant losses for some commercial customers that have electricity as a major input into their outputs and that sell in competitive global markets. That could have large long-run effects on investment by these customers, even if does not substantially affect current output. (The long-run effect can be much larger because over the short run, the assets in such businesses are sunk.) This was the primary reason for offsetting the effects of carbon pricing on trade-exposed emissions intensive industries.
- To the extent that demand is not responsive for any given group, transfers from customers to businesses are large for that group. This has several implications. First, it means that the distributional issues raised in (v) above become relevant. Second, since demand is least responsive when the monopoly business faces few risks of entry by others, it suggests that x-inefficiency may be high. Third, the prize from preserving monopoly rents through lobbying and the political process is large, encouraging wasteful resource use.

3.4 Are deadweight losses passé? New theories of why monopolies should be regulated

The effectiveness and role of benchmarking as a regulatory tool depend critically on the underlying problems that regulations are intended to resolve. Recently, some prominent Australian economists have disputed the relevance of deadweight costs to competition policy, indicating that most economists (including the Productivity Commission) poorly understand the issue:

> The fundamental rationale for public utility regulation has not been well understood, particularly by economists. Mainstream neoclassical economists have argued that the primary rationale for regulation is the minimisation of [the] so-called 'deadweight loss'. But, on close inspection, this hypothesis does not fit the observed facts. (Biggar 2011b, p. 6)[16]

> The current rationale given by most economists, and the approach used by the Productivity Commission (PC), is that we regulate for reasons of allocative efficiency or deadweight loss. That is, the higher prices charged by the unregulated monopolist will see some customers who would have used the facility at efficient prices now choosing not to do so… [However, neither equity nor deadweight costs are the appropriate basis for regulation, and they do not explain the way regulators behave].[17] (Sims 2012a)

16 Biggar has also expressed these concerns in a range of other papers (2009, 2010, 2011a).

17 Paraphrasing the content that followed.

The alternative perspective is that the rationale for price regulation is to create an implicit contract that protects customers' investments from expropriation by the monopolist (a hypothesis explained further below). If this alternative is the correct rationale, this could constitute a major break from the primary expressed basis for regulation of essential services by many international competition authorities.[18] New theories abound in economics and most are not influential. However, when they originate from Australia's premier competition regulator, and have implications for the way it might regulate or advocate policy change, these ideas should be listened to carefully.

In that context, Biggar claims that the contractual approach leads to the imperative for a quite different[19] regulatory framework from the current version. He proposes that:

- consumers should play a bigger role because they are a key party to the 'contract' and more informed about their preferences than the regulator
- the regulator should be an independent arbitrator, not a consumer advocate as its role is to construct the right contract between a monopoly supplier and customers. Accordingly, there would be no grounds for appeals on merit because, as an arbitrator, the regulator would have already fairly addressed both parties' concerns. Appeals should be limited to matters of law, which would also allow the regulator to exercise significant discretion and judgment, rather than to use significant resources 'covering its back' on every issue, given the risk of merit review
- the Rules should not require that the regulator apply the highest cost that just passes a reasonableness criterion, rather than using its best cost estimate, since this favours one party to the implicit contract. Instead, the regulated entity should prove that the regulator's price/revenue proposal is unreasonable
- the object clause in the National Electricity Law should be changed to include long-term price stability, non-discrimination, and a 'no disadvantage' test, so that no customer could be made worse off following a regulatory change (such as those that would arise from a tariff change — for instance, peak load pricing).

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18 The Commission examined the criteria for regulating among various prominent regulators — which all emphasised traditional economic efficiency as a major (if not always the only) motivator for regulation. For example, these included the New Zealand Commerce Commission and major UK regulators (such as Office of the Gas and Electricity Markets, the Water Services Regulation Authority, the Utilities Regulator (of Northern Ireland), and the Financial Services Authority).

19 In fact, some elements are already features of the current framework — a point raised later.

These issues are central to aspects of this report, affecting the potential role of benchmarking in incentive regulation and the scope for increasing network efficiency by removing some of the regulatory constraints network businesses face. Given the above policy conclusions partly depend on the credibility of the new theory, this chapter briefly examines the validity and insights of the theory that led to these conclusions (with a detailed discussion in appendix B).

The new theory: protecting the sunk assets of customers

Biggar's alternative view of the rationale for regulation of monopolies is based on the problem that customers can be held to ransom once they have made sunk investments that use the inputs — such as electricity — of a natural monopoly. A sunk cost is an investment that, once made, cannot easily be recovered by selling it to another party. Some clear examples include the special dies made by a supplier of automotive panels,[20] a person's investment in a qualification, or a specialised product for a particular customer. Not all fixed assets are sunk. For example, as they are usually leased, aircraft are called 'capital with wings'. Nevertheless, many saleable assets would still recover only a proportion of their value when sold — and so are partly sunk. 'Sunkness' is therefore ubiquitous.

Biggar's claim is that:

> … the ***primary*** economic rationale for public utility regulation is the protection of the sunk (relationship-specific) investment of customers of the regulated firm. (2011b, p. 30) (emphasis added)

The logic underpinning this is that:

- Customers of the monopolist make sunk investments whose value is dependent on continued supply of the monopolist's inputs (a 'relationship-specific' investment in the language of this literature).
- Customers know that after they have made the investment, the monopolist can raise prices significantly because, once the investment is sunk, the customer only needs revenue sufficient to cover the marginal costs of supply. The monopolist can therefore expropriate all of the returns that would otherwise have made the investment profitable. Prices would be unstable, varying before and after the investment was made.
- Customers are unable to write *binding* long-term contracts with the monopoly supplier (but regulators can do so on their behalf).

20 This is the classic example given by Klein et al. (1978).

- Vertical integration to internalise the long-term contract within a single firm is often not possible.
- As customers know that the monopolist can behave opportunistically after the investment is made, they do not make the investment at all (the 'hold-up' problem).

Under the hold-up problem, the customer knows that the unregulated monopolist has incentives to expropriate the value of a customer's relationship-specific sunk investments, and the monopolist knows that the customer knows this. Accordingly, the customer will be unwilling to invest (or if so, to a less than optimal level). A customer's decision not to invest reduces the revenue of the monopolist. So, the key hold-up problem is not that the monopolist *will* expropriate the sunk investments of a supplier, but that it must credibly commit *not* to do so to preserve its long-run monopoly profits (which it earns as mark-up on long-run prices). Biggar suggests that regulation solves the problem because it re-creates the long-term contract that parties would have negotiated to protect each party from later opportunistic behaviour.

Moreover, he argues that the theory's validity is strengthened because only it explains why regulators behave as they do. He claims that it explains, among other things, why they apparently:

- encourage price stability to ensure ex ante and ex post prices are the same
- dislike price discrimination because ex post a customer with a large sunk asset has a very low elasticity of demand, and so would face a high price. This would appear to be efficient as a means of recovering the fixed costs of the monopolist, but would do so at the cost of undermining the investment incentives of customers
- do not generally accept peak load pricing, despite its benefits for reducing deadweight losses
- want monopolies only to cover their full costs and not additional rents (because the rents would most likely arise from expropriated sunk investments).

Is the theory compelling as the primary rationale for regulation?

As discussed in appendix B, there are attractions to conceptualising the regulation of natural monopolies in contractual terms. The broad implications of the 'contract' approach appear to echo those resulting from maximising community welfare. That is not surprising given that the only contract that two parties with equal bargaining power would mutually agree to would be one that involved no removable

inefficiencies. The real difficulties arise when the contract approach gives primacy to the 'sunk investment' problem.

Without repeating the detail in appendix B, the main flaws in the 'hold-up' argument are that:

- There does not need to be a single meta theory of regulation of natural monopolies. Hold-up may sometimes be relevant, but in other instances, the concern will simply be that, absent regulation, the consumer would be exposed to excessive prices and the monopolist might live an inefficiently 'quiet' life.
- Most users of electricity do not make the large irreversible investments that underpin the hold-up problem. Moreover, from a pragmatic perspective, it would be very costly for an unregulated monopolist to behave opportunistically in the way supposed by the hold-up problem for millions of customers.
- Even those business customers making very large investments would often able be able to write long-term contracts that would preclude the hold-up problem. Moreover, other non-regulatory solutions like vertical integration could be used where contractual difficulties appeared insurmountable.
- It is also not clear that even were a dominant business to ex post exploit a customer making sunk investments that the solution would be price regulation. Competition laws (as in Article 82 the European Union Competition Law) or oversight of particular long-term contracts that may be subject to hold-up might address any issue in a more targeted way.
- The notion that regulations (and their underpinning laws) create credible long-term contracts belies how regulations change and how regulators behave. Until late September 2012, there have been 51 versions of the Rules. Over an asset life of 40 years (easily possible for network assets), the economic value of the asset would be exposed to nearly 280 sets of possible new regulatory influences during its life. The hold-up problem may be larger under regulation than under unregulated monopoly, which is why the National Electricity Law should be designed to reduce that risk.
- Regulators do not, in fact, say that their actions are based on the hold-up problem — something that would be expected were it to be their true underlying motive for the regulation of natural monopolies. Indeed, they typically refer to conventional arguments about the problems of natural monopoly. Regardless, the idea that a good rationale is revealed by the actions of regulators presumes those actions are always appropriate. The ultimate test is not what regulators do, but whether, given market behaviour and its outcomes, regulation is justified on welfare grounds.

3.5 The alternative policy implications of different theories of monopoly regulation

As noted in section 3.4, the proponents of hold-up reach strong policy conclusions, with significant implications for this inquiry. The policy conclusions fall into several categories,

The conclusions could arise from alternative theories. For example, the importance of empowering consumers and, where possible, involving them in regulatory decisions is consistent with conventional theories of competition regulation. This approach can sometimes overcome asymmetries of information for regulators, achieve 'buy in' by consumer groups that recognise the need for compromise in regulation, and may allow less heavy-handed regulation (where supported by the potential for intervention by the regulator if negotiations are imbalanced). The Commission is in strong agreement with Biggar's (and the ACCC's) views on the importance of a consumer role. The difference is only in the reasoning to reach that conclusion.

Often the policy conclusions are non-sequiturs. It is not clear why the existence of hold-up would justify a no-disadvantage test. The implicit contract struck by the regulator on behalf of a large heterogeneous group of customers and a monopoly business would usually not advantage all consumers. For instance:

- A prohibition on peak pricing would disadvantage those consumers who use less power in peaky periods (who will often be poorer customers).
- Similarly, the fact that the AER should be an impartial arbitrator rather than a consumer advocate — a position the Commission supports — does not preclude significant regulatory errors. Customers or businesses should be able to contest any material errors. The proposed reversal of the onus of proof so that businesses would be obliged to prove the unreasonableness of a determination by the AER would need to be justified on other grounds. This inquiry finds that benchmarking is a useful but inexact tool (chapters 4 and 8). The existence of merit review creates strong incentives for the regulator to be prudent in its application.

The conclusions also fail to consider the long-run interests of customers as a group by taking a narrow approach to the implications of regulatory error on investments. Where a monopoly business provides inputs to many diverse customers — as in electricity networks — opportunistic behaviour by a monopolist can only affect a small share of customers (as shown in appendix B), whereas regulatory error by the regulator can affect the investment adequacy of the monopoly business to the disadvantage of all of its customers. Moreover, the intention of incentive regulation

is to offer some rents ('headroom') as the carrot for a regulated business to minimise its costs and to innovate. Setting the ex ante regulated price at a point equal to that of some hypothetically most efficient business does not allow such headroom, and would be likely to reduce dynamic efficiency — with losses to consumers.

3.6 In summary

This chapter has devoted considerable space to the issue of hold-up because it:

- appears to have gained purchase in some regulatory circles, albeit not uniformly in either its rhetoric or practices
- is a useful thought experiment, whose flaws highlight many of the practical necessities of competition regulation (such as merit review and compromise).

The hold-up problem is a hypothetical and theoretically elegant example of a particular deadweight loss that might sometimes arise were monopolies to be unregulated. However, it is not persuasive as 'the' reason for economic regulation of electricity network businesses, and nor have energy users, the AEMC, AEMO and other major stakeholders perceived market power in this way.

The hold-up idea does not displace the usual efficiency concerns of regulators, governments and economists, and is not required as a basis for the sensible regulation of network businesses. Ironically, were it to actually inform regulatory policy to any great extent, the hold-up construct has the potential to undermine the long-term interests of end users, as it could threaten investment by the monopolist in long-term assets, innovation and cost minimisation. It does not appear to be compatible with incentive regulation (and one possible use of benchmarking). It would be unfortunate were it to assume primacy as the conceptual basis for Australia's economic regulation of electricity networks (or indeed other infrastructure).

There are points of substantial agreement

The differences of view on this issue do not change one essential point. Electricity customers, the ACCC, the AER and the Commission all strongly argue for the economic regulation of electricity networks. Unregulated network businesses would have significant market power, with the potential for adverse effects on customers. Correcting that market power requires nuanced but powerful regulation.

4 A framework for benchmarking

Key points

- Regulatory benchmarking encompasses any method for comparing firms to each other, to themselves over time, or to an ideal firm, in order to measure, and (potentially) encourage, efficiency in the regulated business.
- The literature on benchmarking is confused. There are:
  - multiple methods for benchmarking, with little consensus about which is best
  - divergent views about the appropriate inputs and outputs of electricity network businesses.
- Nevertheless, in Australia and overseas, network regulators have made extensive use of benchmarking, mainly as a tool for assisting their regulatory judgments.
- In Australia, its sophisticated use has been frustrated by inadequate data (and potentially by limitations in the National Electricity Rules) and limited sample sizes.
  - International comparisons can only partially address these limited sample sizes, and create their own challenges in reaching valid comparisons of business performance.
- Incentive regulation aims to improve managerial performance. Accordingly, benchmarking needs to take into account factors outside the control of the businesses.
  - Such an exercise is useful in its own right, as it may help identify policies or regulations that stifle efficiency.
- The path to better benchmarking depends on specifying clear criteria for appropriate benchmarking and systematically applying them. This needs to recognise that the degree of rigor required is dependent on the extent to which benchmarking is used to determine the regulatory outcomes for businesses.
- Benchmarking is not about identifying a single number denoting the efficiency of a business, but rather the potential range of likely numbers.
  - Any benchmarking exercise must take into account the consequences of being wrong.

This chapter is one of five relating to benchmarking of business efficiency. It:

- introduces the concept. Despite its worldwide use, there are many complexities in defining what benchmarking is and its purposes (section 4.1)

- discusses briefly the different methods that are routinely used to undertake benchmarking, and their major technical pitfalls and advantages (section 4.2)[1]
- considers the appropriate measures of network performance and the cost drivers the businesses face (section 4.3)
- reviews the historical use of benchmarking by Australian regulators, including the Australian Energy Regulator (AER) (section 4.4). This section also describes the relevant clauses in the Rules regarding benchmarking. However, whether in fact the AER can actually use benchmarking effectively depends on interpretation of other facets of the Rules — an issue addressed in the next chapter
- discusses the appropriate criteria for the coherent evaluation of benchmarking approaches and the methods used to test these criteria (sections 4.5-4.8). The question of appropriate benchmarking *processes* is distinct, and is addressed in chapter 8.

4.1 Benchmarking managerial efficiency and performance

Regulatory benchmarking encompasses any method for comparing a firm to other businesses, to itself over time (or between its various divisions) or to an ideal firm. Utility regulators around the world use static (and dynamic) 'benchmarking' to encourage regulated businesses to achieve the long-run efficiency outcomes of decentralised, workably competitive, markets. Benchmarking is a well-established method for analysing network businesses' performance, and has been used by:

- Australian regulators, including State based electricity regulators (Pacific Economics 2008, Meyrick and Associates 2005)
- international regulators such as OFGEM (United Kingdom), CER (Ireland), NZCC (New Zealand), and OEB (Ontario Canada)
- various academics in the Australian, European, American and other contexts (see London Economics 1999, Farsi and Filipini 2005, Chanel 2008, Mountain and Littlechild 2010).

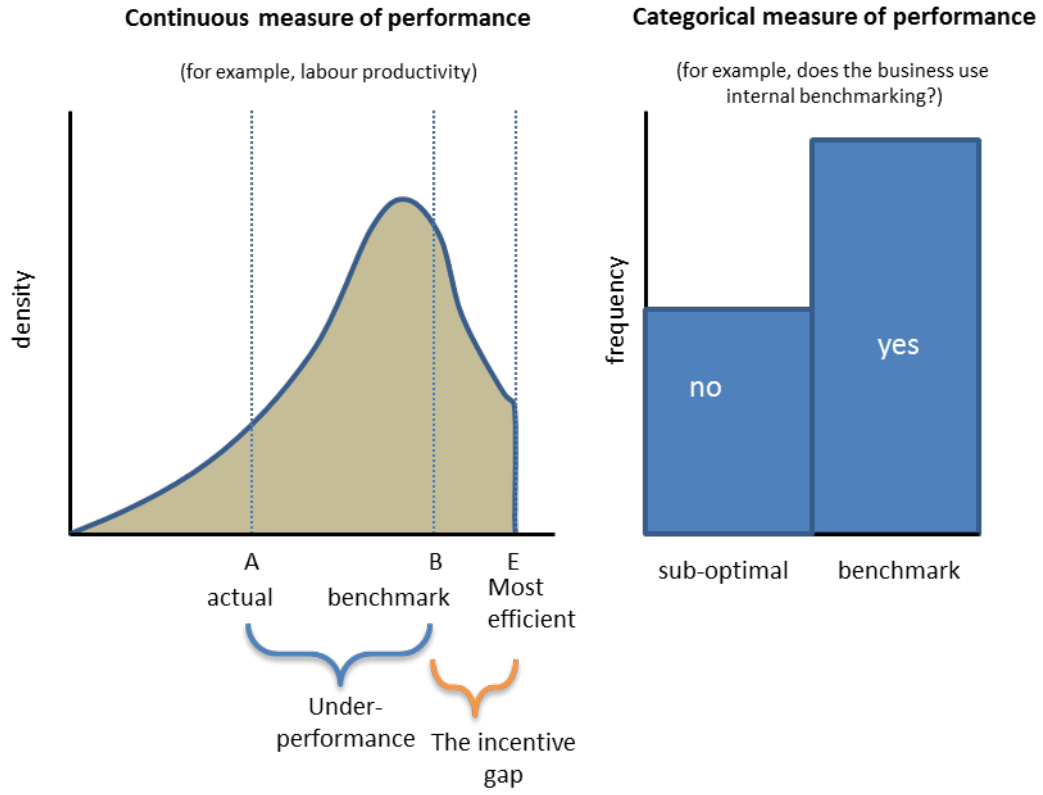
Figure 4.1 depicts the broad types of comparisons underpinning benchmarking. In the left hand chart, a group of utilities have a distribution of efficiency from poor to

[1] At times, this chapter covers some technical matters in order to be useful to practitioners, but the treatment is as simple as possible. The chapter provides references to more comprehensive technical material.

best (the 'frontier'). The challenge of benchmarking is to estimate the *distribution* and make a judgment about some level of acceptable efficiency — the 'benchmark'. It could be at the frontier — but as explained in chapter 5, there are grounds for an incentive gap to provide a reward for dynamic efficiency and to address regulatory error — an issue touched on later and in chapter 8.

Sometimes, benchmarking will relate to a categorical, rather than a continuous measure of performance (or proxy for it). The example in the right hand chart is simply of the yes/no kind, but there could be more than two categories. The surveys used to measure management performance shown in figure 4.2 are based on Likert scales from one to five (Bloom and van Reenen 2010, p. 206).

Figure 4.1 **Benchmarking**[a]



[a] The distribution relates to the measured productivity outcomes for a group of businesses from some benchmarking exercise, with A denoting the measurement for a given business. A is a point estimate — It does not show the degree to which the measured efficiency of A or B is reliable.

What does efficiency mean?

Since benchmarking aspires to increase efficiency, it is critical to unpack this concept. Efficiency has three main dimensions, and relates to the extent to which a business has:

- achieved the maximum possible output from their given inputs (productive or 'technical' efficiency). A simple example would be the labour productivity of vegetation clearance around transmission towers (in a common terrain)
- allocated resources to their highest value purposes ('allocative' efficiency). The extent to which a business achieves this depends on whether it prices its outputs efficiently (for example, with no cross-subsidies) and uses input mixes that truly reflect their relative prices. The current prices paid for power and capacity from photovoltaic cells provides a good illustration. The physical energy outputs of photovoltaic panels is maximised with time invariant feed-in tariffs (an example of productive efficiency). But the *value* of the output (largely derived as network cost savings and as reduced needs for costly peaking generators) is highest at peak use times (chapter 13). In the case of monopoly network businesses, allocative efficiency particularly relates to the potential for businesses to charge prices well above the total costs of output with adverse impacts on businesses using inputs, consumer surplus and the optimum amount of output (chapter 3). In the regulated case, allocative inefficiency is most likely the outcome of inefficient mixes of capital and operating expenditures
- maximised the potential for increasing efficiency over time (dynamic efficiency). For example, this could occur through product and process innovation; investment in management and labour skills that allow flexible responses to changing economic circumstances, and exposure to the risks of insolvency and downsizing.

While all three efficiency measures are important, most benchmarking analysis focuses on the first aspect of efficiency, because it is tractable, and can be used in so-called incentive regulation to encourage the other forms of efficiency. Chapter 5 examines incentive regulation in more detail,[2] but the thrust of the idea is that the regulator:

- calculates some measure of the 'efficient' cost of producing the output of the business using benchmarking, controlling factors outside the influence of the business, so as to target managerial inefficiency.
- allows the business to set prices to recover those efficient costs (including a return on capital).

Under this form of incentive regulation, there is no direct link between the business's *actual* costs and the prices it charges, encouraging businesses to minimise their costs in order to maximise their profits. If the regulator sets a benchmark close to the attainable technical efficiency level, the business has little

2 Joskow (2007) provides a summary of the issues.

prospect of setting excessive prices (thus encouraging allocative efficiency), technically inefficient businesses exit or learn quickly (achieving technical efficiency), while businesses that aggressively reduce costs through better management or innovation make higher than 'normal' profits (dynamic efficiency). As discussed further in chapter 5, this ideal is not feasible, but at least it illustrates the principle.

Many of the network businesses covered in this inquiry have queried the suggestion that they are inefficient in any substantive way. Were that true, the main goal of benchmarking would be to eliminate excessive rents (allocative inefficiency) over time, rather than to penalise technical inefficiency. This would suggest no gain from benchmarking differences in *levels* of productivity between various businesses. Rather, it would imply that a regulator reimburse the business's existing costs in a base year and then adjust allowed revenues over succeeding periods, using an estimate of the rate of total factor productivity (TFP) change, based on historical data, evolving network industry productivity trends, or another unregulated industry. (This is often referred to as the CPI-x or TFP methodology, where x is the relevant TFP growth rate — AEMC 2011b).[3] The Australian Energy Market Commission (AEMC) has carefully reviewed the various disadvantages and (many) advantages of this approach. Its largest advantages are its relative simplicity, the strong incentives it creates for dynamic efficiency and its amenability to be used in negotiated settlements (Kaufmann 2006; Cunningham, sub. 28).

However, the assumption of efficiency in the base year is a strong one. As noted by the Major Energy Users:

> TFP is a form of benchmarking which does result in less prescription but is dependent on the initial allowance being efficient first. If the initial allowance is not efficient, TFP provides for the inefficiency to be perpetuated. Therefore benchmarking is seen as the essential first step to reach the efficient frontier. (MEU, sub. 11, p. 30)

If the assumption of efficiency is not correct, and the regulator does not re-adjust base year costs to the efficient level, the businesses can either still survive while remaining inefficient, or make permanent profits above the normal return by closing the efficiency gap.[4] Neither would be desirable. For example, were the total

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3 The terminology can be misleading. For example, OFGEM's RPI-x mechanism (where RPI denotes the retail price index) is not much different in practice to the approach currently adopted by the AER. This is because the approach still requires an assessment of the efficiency of any given business, and then some decision about the allowable revenue over the regulatory period based on a judgment about the pace of convergence to an efficient benchmark.

4 IRIC (2003) explains why it is therefore necessary to have a base year adjustment or apply higher initial TFP growth rates for businesses estimated as less efficient than the static benchmark in the base year. This means that some static benchmarking would be required.

industry costs around $15 billion in a base year, but efficient aggregate costs were 10 per cent lower, then under reasonable assumptions, using the TFP methodology without base year adjustment would result in cumulative productive inefficiency of around $22 billion in net present value terms.[5] Effectively, the incorrect assumption of efficiency in the base year would be equivalent to the opportunity for customers to receive free electricity network services for one and half years.

The hypothesis that network businesses are currently efficient would be an astonishing result on several grounds.

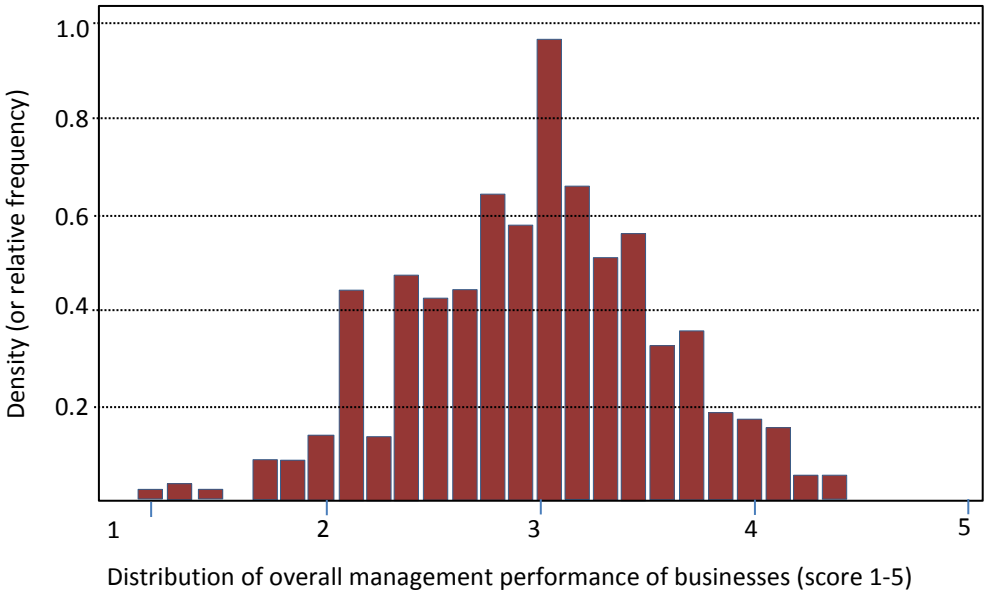
- As discussed in chapter 3, incentives for cost efficiency are blunted when businesses are not exposed to fierce actual or potential competition and have legacy 'cultures' reflecting their past status as effectively non-corporatised government departments.
- The usual factors encouraging dynamic efficiency are, at best, weak in an industry, where, even *after* regulation:
  - businesses cannot be allowed to become insolvent (with the disruption costs and difficulties of ensuring continuity of service quality were that to occur)
  - many businesses, through their state-owned status, cannot ever be taken over in hostile takeovers or merge across state boundaries
  - revenue allowances reward over-capitalisation
  - network businesses are free from normal market competition given their monopoly status, and through the regulatory arrangements, have greater security about returns on their sunk investments than would occur in unregulated markets. Lower levels of competition are generally associated with reduced efficiency (Bloom and Van Reenen 2010)
  - the industry is characterised by large lumpy investments, which makes businesses susceptible to long-lived efficiency impacts from poor decisions. The existing international empirical evidence for highly capital-intensive industries — such as electricity, airlines and telecommunications — suggests that wide divergences in efficiency are unexceptional, notwithstanding the sophisticated nature of the businesses concerned.

Even in competitive markets, there is a continuum of efficiency and performance (Bloom and van Reenan 2010; Syverson 2011). This is demonstrated by figure 4.2 for a large sample of Australian businesses operating in typical market conditions. There is a long tail of poorly performing businesses. A similar dispersion of

5 This illustration assumes a TFP rate of 1.5 per cent per annum, a discount rate of 8 per cent and an economic growth rate of 3 per cent per annum.

performance is apparent in similar studies using the same methods over a large number of countries.[6]

Figure 4.2 **Management performance of Australian businesses generally**
2009



a The data relates to a mixture of business ownership types, sizes and sectors (though mainly in sectors, such as manufacturing, where competitive forces are high). The data were collected as part of a collaborative performance study overseen by the London School of Economics, Stanford University. McKinsey & Company. A higher score represents better performance.

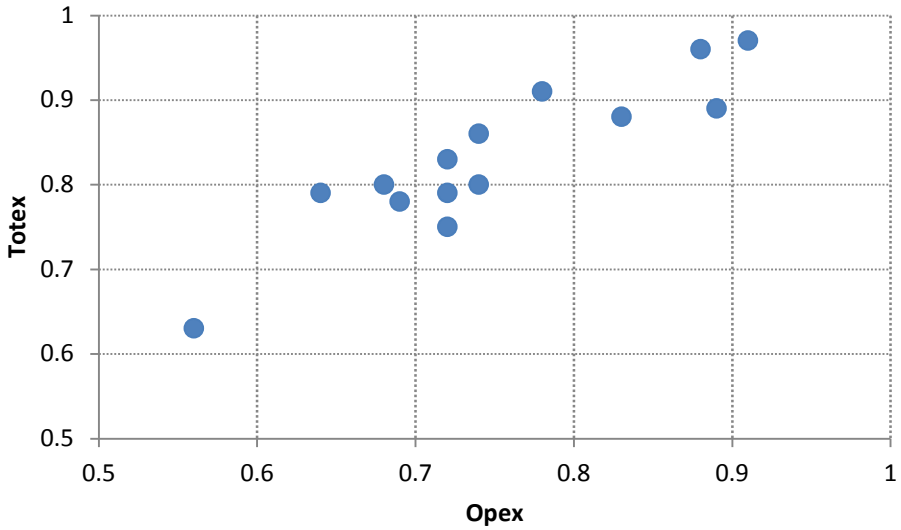
Data source: Macquarie Graduate School of Management et al. (2009, p. 30).

And regardless of the sample size and data deficiencies that might limit the usefulness of benchmarking analysis of Australian network businesses, most overseas studies of electricity network businesses find many are not even close to the efficiency frontier (figure 4.3 presents an example). For example, putting aside the disputed Australian results of Mountain (2011) and Mountain and Littlechild (2010), a large sample study by Chanel (2008, p. 7) found that the least efficient distribution businesses in the European Union had costs more than 80 per cent higher than the most efficient. It is hard to argue that Australian network businesses are exempt from what appears to be a ubiquitous pattern among their international peers (and businesses generally).

The key question for benchmarking is not whether there is inefficiency, but whether there is enough to matter for regulatory purposes.

6 Bloom et al. (2007), Bloom and Van Reenen (2007), Bloom and Van Reenen (2010).

Figure 4.3 **Technical efficiency in electricity distribution in the United Kingdom**[a]



[a] A business with a score of 1 is at the efficiency frontier, while scores below this indicate the degree of inefficiency. For example, a score of 0.6 means that a business is 40 per cent below best practice. In principle, it could increase its output by around 65 per cent (that is 1/0.6 x 100), without any changes in its inputs.

Data source: Yu et al. (2006).

4.2 Benchmarking techniques

Aside from engineering models, the methods used to benchmark electricity networks are similar to productivity analysis of any industry, with the major difference being the relevant variables (figure 4.4).

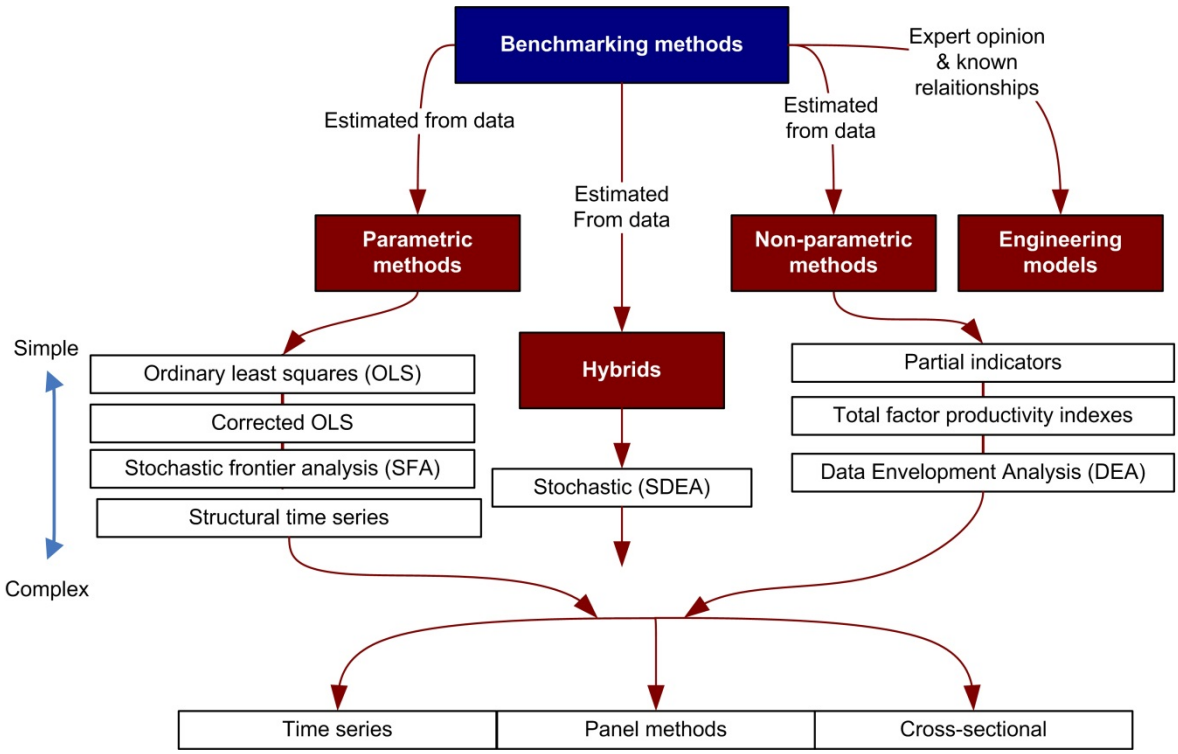
There are four basic approaches to benchmarking:

- statistical methods provide estimates of parameters of a production or cost function, but with information about the imprecision of those parameters
- non-parametric methods do not make any assumptions about the distribution of the population. Such approaches include simple ratios, indexes and linear programming methods
- hybrid methods combine non-parametric and parametric methods (Daraio 2012)
- engineering and reference models are bottoms up models, based on expert knowledge about the operation of networks and the efficient costs of building and operating them. These models (such as the Swedish NPAM model) — create an artificial firm based on engineering and cost information to use as a benchmark, and then feeds in the characteristics of a given network business —

such as its customer numbers, location, and capacity for each transformer station (Jamasb and Pollitt 2007a; Strbac and Allan 2001). In Australia, Elder and Beardow (2003) developed a model of an idealised electricity distribution network for regulatory pricing (among other reasons), but it is not clear it has been used for that purpose.

Figures 4.5 and 4.6 depict graphically how the various methods measure efficiency.

Figure 4.4 Different benchmarking approaches[a]



[a] OLS is a regression approach that minimises the sum of squares of the errors of a line passing through the data. The dependent variable could be in log form or some other transformation. (While not shown above, non-linear least squares — a variant of OLS — does not impose linearity.) Corrected OLS shifts the line up just until there is one observation with a measured efficiency index of one. Stochastic frontier analysis takes account of the fact that errors around the regression line comprise statistical noise and systematic (one-sided) inefficiency. Structural time series models take account of the fact that parameters may shift over time (for example due to structural shifts or slowly declining or increasing productivity growth). Non-parametric methods are simple ratios (akin to those used in chapter 6). Total factor productivity (TFP) indexes are based on weighted inputs and outputs over time. Data envelopment analysis is a linear programming approach that connects the outer envelope of productively efficient businesses, while stochastic DEA takes account of the influence of statistical noise. The approaches can apply to a snapshot of businesses at a given time, time series for specific businesses, or panel data methods that use cross-sectional and time series data.

The literature on the various methods is vast. This inquiry does not examine these methods in any detail since there are multiple textbooks, software tools and review

papers in this area. The AER has been responsible for two of the most comprehensive and useful papers.[7]

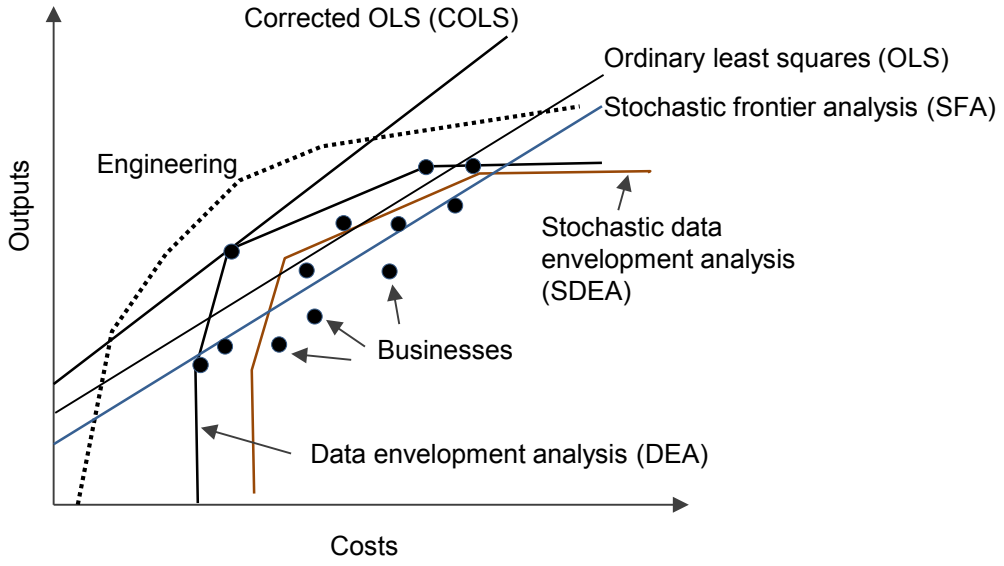
Notwithstanding the volume of research and empirical work, there is no consensus about the best benchmarking measures (or even the appropriate inputs and outputs — section 4.3). In 2001, two leading economists in the area effectively said they did not know what approach to advocate:

> … there is no firm consensus on how the basic functions of the utilities are to be modelled. (Jamasb and Pollitt 2001, p. 114)

That view did not change much in the ensuing decade. For example, in their consideration of the issue, Growitsch et al. (2010, p. 3) reiterated:

> Although, from a technical point of view, distribution networks can be regarded as relatively simple activities, there is no consensus in the academic literature or among the regulatory practitioners as how to model this activity.

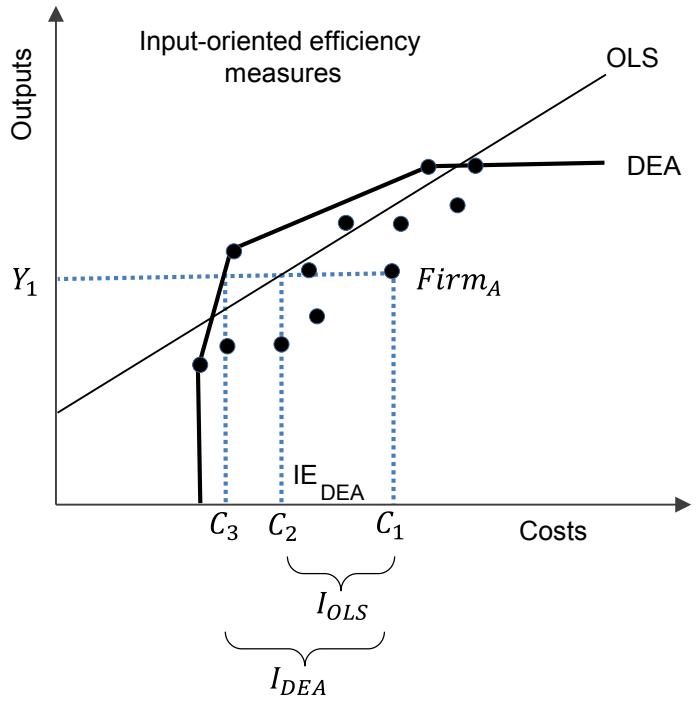
Figure 4.5 **Benchmarking methods**



Source: CREG & SUMICSID (2011, p. 26).

7 The ACCC/AER (2012a) provides a comprehensive update on benchmarking approaches. The AER also commissioned a thorough analysis of European approaches (Schweinsberg et al. 2011) as input into ACCC/AER (2012b). In this inquiry, Cunningham (sub. 28) provides an accessible treatment of the different methods and their use in incentives regulation. Filippini et al. (2005) also covers the various techniques. There are numerous software packages for undertaking benchmarking, such as the various programs from the Centre for Efficiency and Productivity Analysis at the University of Queensland (DEAP, DPIN,Frontier, and TFPIP); LIMDEP, STATA, and OpenSolver for Excel.

Figure 4.6 **Illustrating the measures of inefficiency**[a]



[a] An input-oriented measure of inefficiency is the reduction in inputs for a given output level that a firm could achieve if it became efficient. So, firm A produces output Y1 at cost C1. Using the linear regression approach, it could produce Y1 at cost C2, so that its current inefficiency is C2/C1. Using data envelopment analysis, it could produce Y1 at cost C3, so that its inefficiency is C3/C1. Similar measures can be obtained by using the same approaches for the other estimation methods shown in the previous chart.

In the United Kingdom, Frontier Economics (2010b, p. 6) recommended ordinary least squares (OLS) or corrected OLS (COLS), but not stochastic frontier analysis and data envelopment analysis (DEA). Other analysts suggest that DEA is more robust and makes fewer underlying assumptions. Yet again, others regard the TFP index approach as the most simple because it uses overall industry productivity growth as the basis for incentive regulation, without reliance on the specific performance of the business.[8]

The various preferences of regulators are revealed by significant variations in benchmarking practices around the world (table 4.1). Even in countries where benchmarking has been routinely applied, regulators of different utilities have tended to adopt different approaches, without any sign of convergence. As one analyst in this area noted in the UK context:

8 Kaufmann (2009) has argued that TFP benchmarking is less vulnerable to data inconsistencies than the building block process currently employed. This is true if TFP benchmarking is based on the growth rate of State-wide TFP, as had been suggested by the Victorian Essential Services Commission. Lawrence's judgment is that it depends on the context and that TFP results can still be quite sensitive to data errors (Lawrence 2009, p. ii).

Moreover, it is not obvious that over time there has been a movement towards some form of consensus across the regulatory offices on the role of benchmarking. (Dassler et al. 2006, p. 172)

Table 4.1 **What do other countries do?**
Network benchmarking around the world

Location	*Method*	*Source*
Chile	Engineering	Farsi et al. 2007
Denmark	Ratios	Nordic Energy Regulators 2011
Finland	DEA/SFA/SDEA	Nordic Energy Regulators 2011
Netherlands	DEA/Ratios	Farsi et al. 2007
Norway	DEA	Nordic Energy Regulators 2011
Sweden	DEA/Engineering	Jamasb and Pollitt 2007b
Spain	Engineering	Schweinsberg et al. 2011
Austria	COLS/DEA	Schweinsberg et al. 2011
Ireland	COLS	ACCC/AER 2012b
New Zealand[a]	TFP index	ACCC/AER 2012b
Ontario	TFP, ratios	ACCC/AER 2012b
Japan	Econom tric	ACCC/AER 2012b
California	TFP, econometric	ACCC/AER 2012b

[a] The New Zealand Commerce Commission (2010, pp. 640-45) has recently proposed a novel application of benchmarking. Independent verifiers, effectively external auditors (paid for by the businesses), must provide independent evidence in support of the business's proposal — and are free to use a range of quantitative techniques, including benchmarking.

In this context, the AER's verdict about the state of the technology is not surprising:

> There is no clear consensus in the literature in relation to which benchmarking approach should be used by economic regulators. As identified previously, each method has relative strengths and weaknesses. (ACCC/AER 2012a, p. 136)

4.3 What should be benchmarked?

In many industries, it is clear what inputs and outputs are. This is not so straightforward in electricity networks (and other networks, such as rail[9] and telecommunications). In part, this is because electricity networks are very complex. For instance, there may be discontinuities in cost functions and counterintuitive relationships:

> … the effects of Kirchhoff's laws lead to bewildering irregularities in the relationship between outputs and capacities … As a result, transmission cost functions are likely to have strange properties that make them interesting for an audience outside electricity. Where else can you expect to have negative marginal costs? (Rosellón et al. 2009, p. 1)

9 As noted by IRIC (2003, p. 18).

These esoteric complexities aside, a comprehensive analysis of benchmarking prior to 2001 found no unanimity about the appropriate variables to include (Jamasb and Pollitt 2001, p. 114). Given the AER's (2012) recent literature review, this situation has persisted. As Turvey (2008a, p. 2) put it:

> Comparisons between networks of the costs of these activities can only illuminate differences in the efficiency with which operations and maintenance are carried out if the magnitudes of the tasks of operation and maintenance can be compared. This is a platitude, yet failure to articulate it has led some authors to scrabble around among available data to select a set of "explanatory" variables without displaying any understanding of what an enterprise does and how it does it. Confusion about these matters is rife, as witnessed, for example, by the fact that while some econometric efficiency estimates for electricity distribution treat MWh distributed, km of overhead lines or number of customers as an input, others treat one or more of these variables as an output!

As an illustration, while some consider that energy transfer across networks is an output, in fact, network businesses do not determine how much power is transferred across their lines (in contrast with generators). The APA Group (sub. 2, pp. 1-3) observed:

> The benchmarking of electricity business' productivity (and TFP benchmarking in particular) almost always uses energy delivered as the output measure … This is highly problematic, as energy delivery (and hence apparent network productivity) is responsive to price changes for reasons such as the carbon tax and fuel prices.

Fundamentally, network businesses provide capacity and quality to customers, analogous to the services provided by roads (Frontier Economics 2010b, pp. 41ff). Accordingly, outputs (or cost drivers) would include:[10]

- customer numbers (new connections raise costs) by type (commercial and household)
- the capacity to carry power to dispersed customers (through transformers, network kilometres, by the level of kV) when it is required. This would need to consider network types, such as the mix of central business district, urban, short rural or long rural assets (ETSA Utilities, CitiPower and Powercor Australia sub. 6, p. 32)
- ensuring adequate quality (reliability requirements) and low transmission losses
- the capacity to cater for peak demand (the load factor or peak to average demand measures).[11] If this variable is not available, then energy supplied may be a

[10] Several participants made suggestions about the appropriate variables. These resembled the diversity of those suggested in an international context (Ergon Energy sub. 8, p. 10; ATSE sub. 9, p. 1).

practical control variable, since otherwise an over-engineered network with excessive capacity may appear to be efficient.

- input prices (as suggested by Ergon Energy, sub. 8, p. 10 and the ENA, sub. 17, p. 30).

If there is an insufficient sample for estimation, composite cost drivers may be relevant (widely used by OFGEM, but declared to be 'arbitrary' by NERA 2007, p. 3, pp. 29ff).

It is also important to distinguish short-run efficiency (where the focus is on operating expenditures) from long-run efficiency (where capex *and* opex are the relevant cost). While generally in favour of the greater use of benchmarking in regulatory determinations, the MEU acknowledged this limitation:

> … benchmarking of capex is less readily applied due to the "lumpiness" inherent in some of the capital investments required in the energy transport sector. This, of course, should not be a reason not to benchmark. … This requires the excision of the large augmentation projects (the "lumpiness") from the capex program and then benchmarking becomes essentially straightforward and useful. The few "lumpy" elements can be assessed in their own right. (sub. 11, pp. 17–18)

The ratio of replacement investment to the age-weighted value of existing capital stock provides one indicator of whether rising capex reflects the (efficient) need for the orderly replacement of older assets (Ausgrid sub. 19, p. 6). Others — such as NERA (appendix B of ENA sub. 17) — argue that the relevant metric is the share of assets close to expiry.

4.4 The use of benchmarking for Australian electricity networks

The use of benchmarking under previous regulatory regimes

Prior to the creation of the AER, state and territory regulators often used benchmarking of electricity networks as a tool, but not in determining revenue allowances (box 4.1). Several regulators used benchmarks to test the reasonableness of proposals (IPART, QCA, ICRC). Others used benchmarks to flag areas that might need further analysis (ETSA) or to assess a base year expenditure (ERA). In

11 EnerNOC (sub. 7, p. 4) considered that the best measure was the proportion of the peak load that appears for 40 hours or less in a year, but acknowledged that 40 hours was a fairly arbitrary choice (with values from 10 to 80 hours all being reasonable).

other instances, benchmarking has apparently not been influential (OTTER, NTUC). Chapter 6 examines these studies' empirical estimates of network inefficiency.

Box 4.1 **State and Territory regulators' use of regulatory benchmarking**

State and Territory regulators have used partial productivity indicators to benchmark electricity network performance:

- IPART compared various expenditure ratios over time for New South Wales distribution networks, using data from the years 1999-2000, 2003-04, and 2008-09. The results were used to test the reasonableness of expenditure allowances.
- ICRC compared ActewAGL with five Victorian distribution networks across various opex ratios, using data from 2002-03. The results were used to test conclusions about expenditure allowances.
- ESC (Essential Services Commission Victoria) compared a deconstruction of opex growth to measure partial factor productivity. Trend analysis was also carried out for capex, comparing networks from Victoria, New South Wales and New Zealand. The opex comparisons were carried out to determine the 'rate of change' and 'growth factor'.
- QCA compared opex rations between Energex, AGL, United Energy and Energy Australia. Capex ratios were compared between Energex, Ergon and Victorian distribution networks. The results contributed to the assessment of reasonableness for expenditure proposals.
- ESCOSA compared expenditure ratios between ETSA and 10 other distribution networks. The results were used to identify areas requiring further analysis.
- Office of the Tasmanian Economic Regulator (OTTER), conducted trend analysis for opex and capex using data from 2002-03 to 2011-12. The results were not considered in the determination.
- Economic Regulation Authority (ERA WA) compared actual opex between Western Power and all other Australian distribution networks for 2007-08. The results were used to assess the base year expenditure for 2007-08.
- NTUC used a 'multilateral unit opex' method to benchmark opex for water and energy utilities.

Regulators have also undertaken benchmarking using comprehensive indices such as TFP:

- The Northern Territory operates a CPI-x framework for the escalation of network prices, using estimates of productivity to determine the X factor. The industry TFP growth trend is used in the calculation of the x factor.

Source: ACCC/AER (2012a), tables 2.2 and 3.3.

Notably, the Northern Territory relies particularly heavily on comprehensive benchmarking to determine the rate of growth in their CPI-x framework.[12]

Benchmarking in the current regulatory framework

The Rules specify that the AER must 'have regard to' benchmarking (box 4.2), and indeed, the AER has used it in its regulatory determinations (box 4.3). However:

- While the AER has commissioned various consultants to undertake benchmarking analyses in the various distribution determinations, the consultants have used different benchmarking techniques, with varying access to industry-knowledge and data.
- Not all networks have been analysed using the same modelling processes. For instance, the Repex model was only developed in time for use in the Victorian distribution determination, and has yet to be applied to several other jurisdictions (AER 2011a, p. 11).
- The results of any benchmarking exercise have typically only informed the AER's state-specific revenue determinations, even though there may be clear implications for other jurisdictions.
- The AER (and others) have indicated that it has made limited use of benchmarking and has focused on ratio analysis (AER, sub. 13, p. 14).[13] The Major Energy Users (sub. 11, p. 12) claimed the regulatory use of benchmarking had 'been supported in principle but has become somewhat inconsequential in practice.' The AER has claimed that the Rules have frustrated its capacity to set a revenue allowance using benchmarking (sub. 13, p. 14), thus limiting its usefulness, but this is disputed (an issue considered further in chapter 5).

12 The X factor is of the form X1 + X2 – X3 where: X1 is the difference between the TFP growth for the electricity distribution industry in Australia and that for the economy as a whole; X2 is the difference between the best observed opex partial productivity level in comparable electricity distribution businesses in Australia and that of Power and Water Power Networks (PWPN); and X3 is the difference between the input price growth for PWPN and that for the economy as whole (GHD Meyrick 2008, p. ii).

13 What 'limited' means is a matter of judgment. ETSA Ultitlies, CitiPower and Powercor Australia (sub. 6, p. 3) indicated that the AER has used benchmarking extensively. The difference of view centres on the sophistication and function of the benchmarking, not the number of times it has been used. As the ENA (sub. 17, p. 4) pointed out 'the key question is how the AER's use of benchmarking can be enhanced in order to improve the accuracy of [network expenditure forecasts] (sub. 17, p. 4).

Box 4.2 The Rules and benchmarking

The National Electricity Rules (v. 51) makes 25 references to 'benchmarking' or 'benchmark', predominantly relating to the financial variables that determine the weighted average cost of capital. However, for the purposes of this inquiry, the most important references are to the opex and capex of distribution and transmission networks. Considering transmission networks, the Rules stipulate various decision-making stages:

The AER must accept reasonable opex:

- Clause 6A.6.6(c): The AER must accept the forecast of required operating expenditure of a Transmission Network Service Provider that is included in a Revenue Proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects: (1) the efficient costs of achieving the operating expenditure objectives; (2) the costs that a prudent operator in the circumstances of the relevant Transmission Network Service Provider would require to achieve the operating expenditure objectives; and (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The AER must reject unreasonable proposals:

- Clause 6A.6.6(d): If the AER is not satisfied as referred to in paragraph (c), it must not accept the forecast of required operating expenditure of a Transmission Network Service Provider that is included in a Revenue Proposal.

The AER must have regard to benchmarking when evaluating reasonable and unreasonable proposals:

- Clause 6A.6.6(e): In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the operating expenditure factors): … (4) benchmark operating expenditure that would be incurred by an efficient Transmission Network Service Provider over the regulatory control period [among 13 categories].

The AER can put in substitute estimate, but subject to conditions:

- Clause 6A.6.6(f): If, in its final decision on the Revenue Proposal under rule 6A.13, the AER does not accept the total of the forecast required operating expenditure for the regulatory control period under paragraph (d), then the AER must, in accordance with clause 6A.13.2(b), use a substituted forecast of required operating expenditure.

There are parallel requirements for capex for transmission businesses (clause 6A.6.7(c), 6A.6.7(d), 6A.6.7(e)(4), and 6A.6.7(f).

There are similar, but not parallel clauses for distribution network businesses:

- for opex (clause 6.5.6 (c), 6.5.6 (d), 6.5.6 (e)(4))
- for capex (clause 6.5.7 (c), 6.5.7 (d), 6.5.7 (e)(4)).

The two important differences are that for distribution network businesses, the clauses relate to the business's 'building block' proposal, and the capacity for a substitute estimate is subject to greater conditions (chapter 5).

Source: National Electricity Rules, version 51.

Box 4.3 **Examples of benchmarking in AER determinations**

On behalf of the AER, Nuttall Consulting (2011) benchmarked Aurora's expenditure levels against several other networks. This included various ratios of capex and opex. Comparisons were made against other networks, states, or regions (for example, rural Victoria). Nuttall Consulting (2010a) also benchmarked Victorian distribution expenditure levels and ratios against those of other networks and States.

Wilson Cook (2008) analysed measures of expenditure for distributors in the ACT and New South Wales, and compared them with a subset of other networks. A bottoms-up analysis was also undertaken, and recommendations were based on both sets of results.

Parsons Brinckerhoff (2009a, 2009b and 2010) compared opex measures for Queensland and South Australian distributors against other networks.

ETSA Utilities et al. (sub. 6, p. 24) noted that network businesses themselves have submitted benchmarking results, for example in relation to opex. These businesses (pp. 60ff) also gave a comprehensive account of the benchmarking undertaken by the AER in respect of Victorian distribution network service providers (and how these results demonstrated the efficiency of the Victorian businesses).

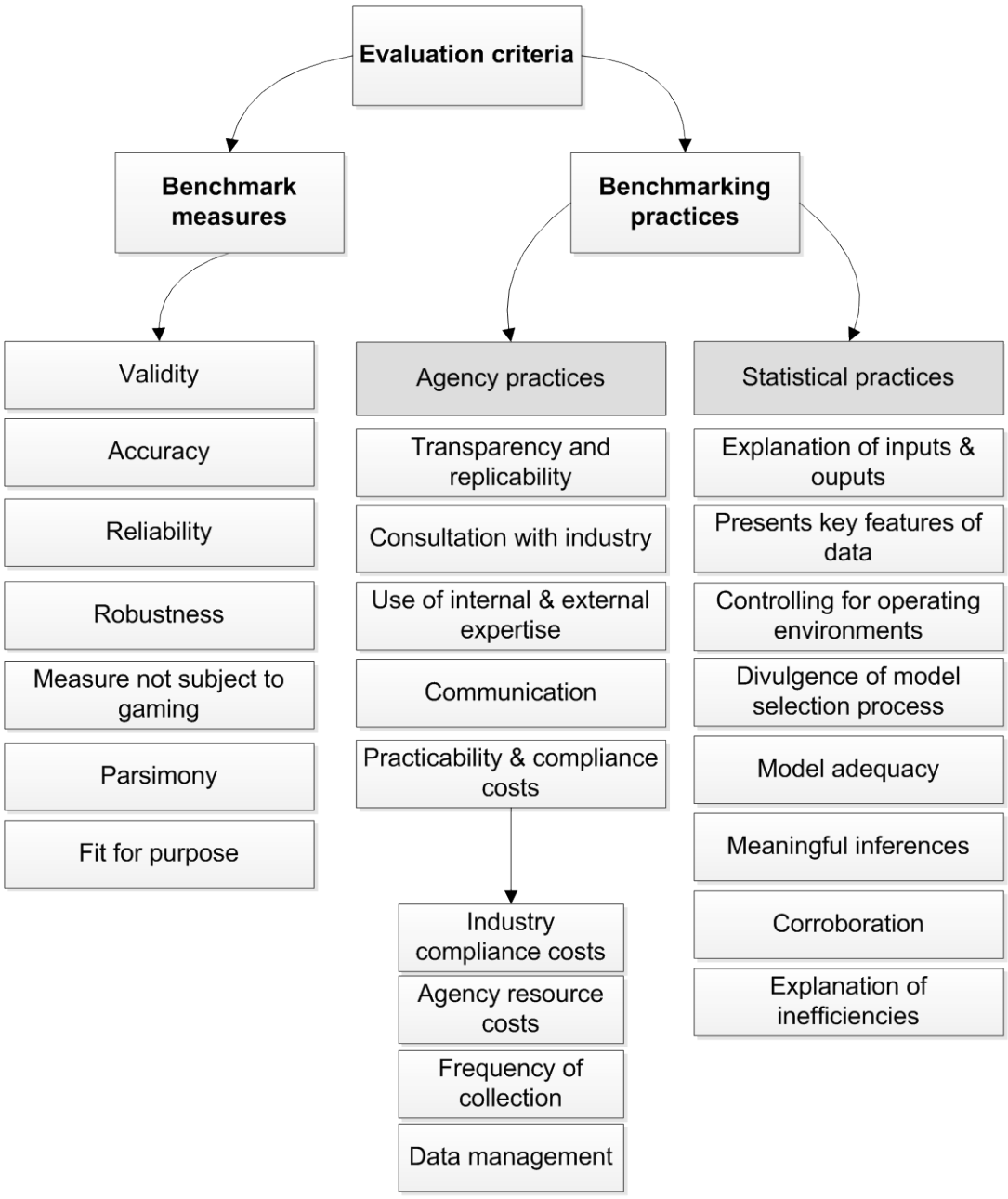
Sources: Nuttall (2010a, 2011); Parsons Brinckerhoff (2009a, 2009b, 2010); Wilson Cook (2008).

4.5 Criteria for judging benchmarking

There are many benchmarking methods (as discussed above), multiple uses for these, varying processes for testing them and different regulatory practices for gathering data, communicating results, and addressing compliance burdens. A key question is how to separate the wheat from the chaff among the various competing approaches, recognising that this will typically involve balancing various criteria (figure 4.7).[14]

14 Participants in the inquiry had overlapping criteria for judging benchmarking. For example, ETSA Utilities et al. (sub. 6, p. 25) identified nine criteria: communication, consultation, consistency, predictability, flexibility, independence, effectiveness and efficiency, accountability and transparency. Ausgrid (sub. 13, p. 5) and the ENA (sub. 17, pp. 4-5) recommended robustness, transparency, promotion of efficiency, consistency with the wider regulatory framework, reasonableness of data requirements, adaptability and resource costs. These are similar criteria identified by Frontier Economics (2010b) for OFGEM in the United Kingdom. Kaufmann and Beardow (2002) noted similar criteria, but added the importance of capturing business conditions — an issue to which this chapter returns later.

Figure 4.7 **Evaluation criteria for benchmarks and benchmark practices**



It is useful for any discussion of such criteria to break them into three subgroups:

- the characteristics of a good benchmark from a scientific perspective, of which validity is the initial consideration (sections 4.6 and 4.7)
- the statistical processes used by the analyst to test whether any result is likely to be useful for its regulatory purpose (section 4.8)
- the processes used by the regulator in undertaking benchmarking. (This issue is examined in chapter 8, which relates to how the AER should use benchmarking.)

4.6 Validity — does the measure test what it claims to?

A valid benchmark should relate to the relevant concept — efficiency (or conversely inefficiency) in one or more meaningful dimensions.

A low failure rate (in say minutes lost per customer) is not a measure of efficiency if customers do not value the reliability benefits above the costs of achieving them (chapter 14).

Similarly, while higher revenues per connection *could* be a reasonable measure of inefficiency (as claimed by Mountain 2011 and Mountain and Littlechild 2010):

- that is not necessarily true. For example, higher revenues of one business compared with others may reflect a regulator's reasonable decisions about the weighted average cost of capital (WACC) at the time of the regulatory determinations
- it is not clear to what type of inefficiency it relates. A high revenue per connection could reflect an inefficiently high WACC (leading to excessive prices, with deadweight costs for customers, but not necessarily excessive investment), or low productivity, or both. Accordingly, it is not a valid measure of its separate components. Data permitting, a better approach would be to break revenue per connection down into its price and productivity components, since these have different implications for policy. For instance, if the business was technically efficient, but the WACC was too high, the regulator would concentrate on the latter in its determinations.

An overarching concern is that any valid benchmarking measure should reflect the way that the businesses are run. As Turvey put it in relation to opex benchmarking:

> Applying different econometric methods to find which method and which of such variables give the 'best' results is very different from the down to earth approach of understanding the industry sufficiently well to identify and describe the immediate determinants of the operations and maintenance work actually required. (2008b, pp. 2-3)

Valid benchmarks of efficiency will often need to take account of time

Efficiency has a time dimension. It can be efficient to 'over-invest' in certain assets ahead of their full utilisation because investment must precede production or because it can be less costly to build in spare capacity at a given time, than to

re-invest at a later time to add further capacity.[15] One of the reasons for the recent slowdown in measured productivity of the Australian economy is that mining companies made large investments ahead of the extraction of output. Few suggest that the Australian mining industry is inefficient for this reason.

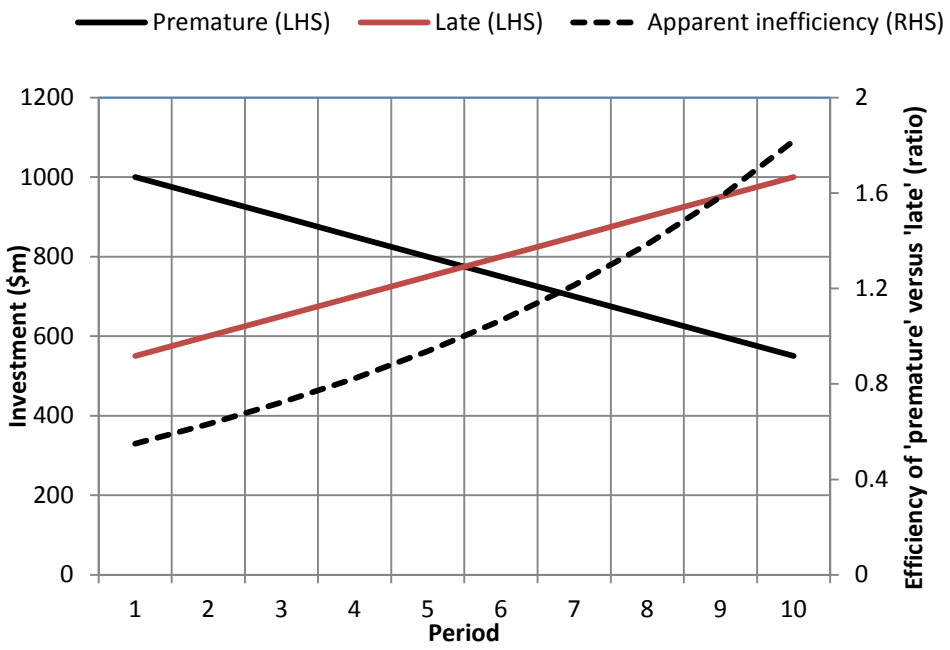
Benchmarks that fail to recognise the implications of timing can be misleading. For example, suppose that a business invests prematurely compared with a comparator, which invests later, but that both make the same real investments over a 10 year period. Assume for illustrative purposes that the outputs of the businesses are identical in each year. In the example shown in figure 4.8, the comparative investment rates required to achieve a given output — a measure of their relative investment efficiency — suggests that the 'inefficient' firm is grossly inefficient for the initial years. Yet in present value terms over the 10 year period, the premature firm's inefficiency is less than 8 per cent. Using snapshot efficiency measures for the first few years would not provide a valid measure of the real efficiency gap between the businesses. Static measures are still useful, but need to be carefully interpreted.

Controlling for factors outside the control of business and their relevance to valid conclusions about inefficiency

There is a large literature on estimating the comparative costs of businesses, with much of that literature concentrating on using the 'right' techniques. However, it is equally important to be clear about how to interpret benchmarking results for policy purposes because the misuse of good technical analysis can result in adverse outcomes for consumers and businesses. In particular, comparing the costs between businesses in different jurisdictions without accounting for factors outside the control of the business could provide misleading indicators of managerial efficiency. If used in incentive regulation, this could lead to underinvestment or unwarranted transfers from consumers to the businesses.

15 Growth rates in past demand also have implications for the asset type and scale economies (ENA sub. 17, p. 30). A business experiencing low and steady growth will tend to (efficiently) have a large number of smaller transformers and other equipment that will need to be operated and maintained. In contrast, a business that has experienced large waves of growth will (efficiently) have a smaller number of large-scale assets that need to be operated and maintained (because large scale assets can be built with less average underutilisation when demand is growing faster).

Figure 4.8 **Efficiency often needs to be dynamically assessed**



a The efficiency ratio is simply the ratio of the real value of investments in a given year.

Data source: PC calculations.

The measured level of comparative business performance across Australian and international jurisdictions reflect four broad factors.

Managerial inefficiency

Managerial inefficiency may be manifested in many ways. A network business may not organise itself efficiently, resulting in higher than necessary costs and/or poorly structured prices. It is important to emphasise that managerial inefficiency is primarily not about the performance of managers per se, but primarily about how the governance and organisation of a business can affect any aspect of its performance. For example, a business may be overstaffed, have insufficient expectations of workplace productivity, be overly combative or passive in its dealing with its unions, and over-invest. Managerial inefficiency does not always mean ineptitude or lack of industriousness — highly competent people can pursue inefficient outcomes with hardworking gusto. Moreover, a business could make the most efficient use of its resources at a given time, yet still be encumbered with an inefficient (sunk) capital stock that reflected investment decisions made by previous managers.

Inefficiency also comes in different sizes. The critical concern is not the presence of inefficiency per se, as no industry is perfectly efficient, but whether the divergence in efficiency matters from a policy perspective.

Environmental differences outside the control of the businesses and government

Network businesses are justifiably concerned about 'like with like' comparisons.[16] Many of the criticisms levelled by network businesses against the benchmarking findings of Mountain and Littlechild (2010) reflect their concerns that the analysis did not control sufficiently for extraneous differences in the operating environments of the businesses.[17]

Network businesses operate in different environments that are outside their and government control, including the physical aspects of that environment (topography, forestation, climate, soil type, temperature and wind), customer density and type; the form and location of generators, and the prices of inputs, such as wage costs and the costs of wires and substations.[18] For example, the efficient costs per customer of providing network services to highly dispersed customers in a rural region are greater than the costs of providing services in a city suburb (figure 4.9). In relation to its own network, Ergon Energy indicated that its:

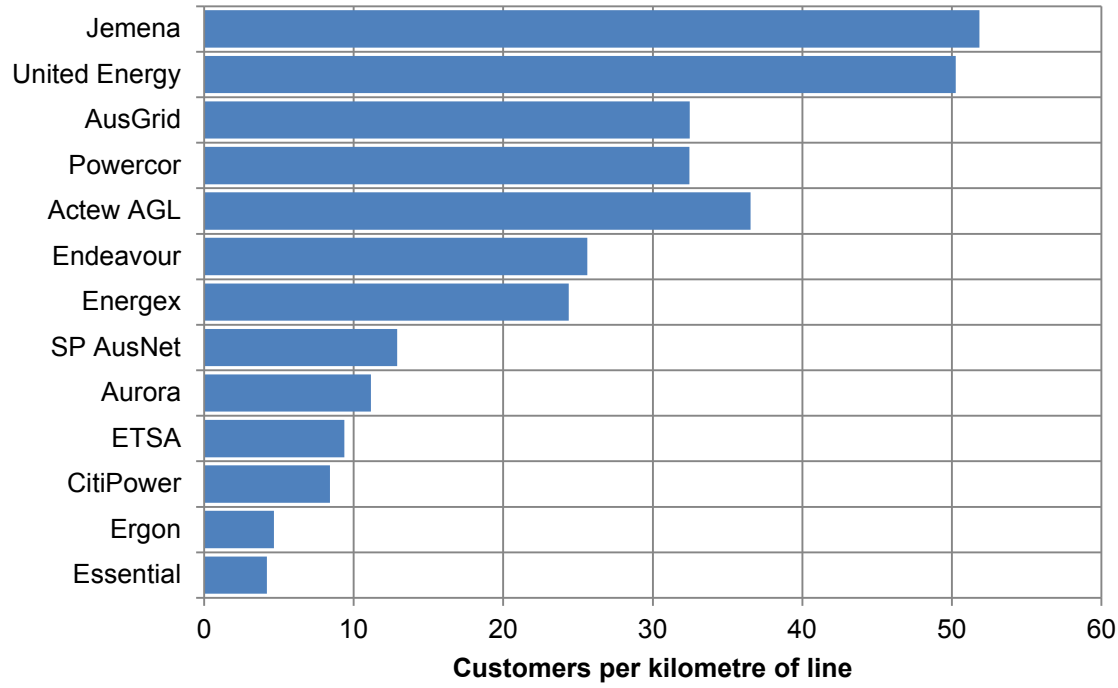
> … network area covers more than one million square kilometres, which is over six times the size of Victoria. This network characteristic would impact on our performance against reliability standard targets due to accessibility issues and distance to travel to faults. (sub. 8, p. 3)

16 Some accepted that it was possible to meaningfully benchmark the weighted average cost of capital (ETSA Utilities et al. (sub. 6, p. 29). The Commission considers some of the problems in this area in chapter 5, as they relate mostly to the capacity for the AER to effectively use other kinds of benchmarking in incentive regulation.

17 On the other hand, the MEU (sub. 11, p. 24), which has commissioned research by Mountain, argued that 'networks try to minimise the use of benchmarking on the grounds that their network is different.' This is why statistical testing and engineering appraisal of benchmarking models to test for important omitted variables is critical.

18 This was reflected in submissions from Ergon Energy (sub. 8, p. 7), Actew-AGL (sub. 14, p. 2), the AEMC (sub. 16, p. 2), the ENA (sub. 17, pp. 30ff), Ausgrid (sub. 19, p. 8), the EUAA (sub. 24, p. 7), Essential Energy (sub. 30, p. 4), and Grid Australia (sub. 44, p. 3). As an illustration, the difficulties in controlling for environmental factors meant that the Brattle Group (2012a, p. 48) found there was no clear relationship between the costs of the distribution networks they reviewed and the reliability performance they achieved.

Figure 4.9 **Customer density differs between networks**
Customers per km of distribution line



Data source: AER (2011b); Distribution network websites and annual reports.

Some participants pointed out the need to engage with the business's actual operations at a detailed level:

> … it may be that poles are twice as expensive in one jurisdiction compared to the other (e.g. due to different proximity to a hardwood industry - noting that poles are expensive to transport). (ENA sub. 17, p. 28)

In certain instances, it is difficult to categorise definitively whether a factor is fully outside the control of the business:

- peak demand can be partly controlled by the businesses given they can undertake demand management programs (AER 2010a). Failing to account for this in benchmarking could discourage further improvement of demand management programs (chapters 9 to 12)
- businesses provide advice on reliability standards
- in many cases governments, rather than network businesses, make the decision about whether to put cables underground — which lies clearly outside the control of the businesses. However, in some other instances, network businesses will make the decision to install cabling underground ('undergrounding') because it increases reliability and reduces vegetation clearing costs, or because

there is a mutual benefit to them and to co-contributing customers from undergrounding. Consequently, were businesses sometimes to overinvest in undergrounding then this would not show up as inefficiency were a benchmarking exercise to control for all undergrounding.

Policy differences

Network businesses in different jurisdictions are sometimes subject to different regulatory and policy frameworks, which are outside the business's control, but within governments' control. Such policies and regulations can affect a network business's practices, costs and productivity. For example, governments may set reliability standards (ENA sub. 17, p. 7), may own the business concerned (a policy choice of government, not the business), and where state-owned, stipulate their governance arrangements or give them non-commercial directions (chapter 7). Governments may also mandate various environmental policies — such as feed-in tariffs for household photovoltaic generation — that may physically affect the efficiency of the network and add to overall customer prices, reducing power demand, and utilisation of the network (chapter 13).

This is relevant to policy in two ways:

- benchmarking for incentive regulation needs to control for any important policy/regulatory arrangements that affect business performance
- the information from controlling for such arrangements in any benchmark modelling can be used to improve aspects of the policy environment (such as divergent and unjustified differences in reliability standards; or limits on the use of demand management through price controls). When reporting on its benchmarking modelling results, the AER should highlight publicly any major effects on productive efficiency from policy and regulatory settings.[19] A major reason for the Commission's consideration of ownership, demand management, and reliability is that these may be a source of greater inefficiencies than the managerial practices per se. For example, IPART (2010, p. 49) commented that the quality of network planning and the decisions on the licence conditions that drive capital expenditure will be critical for future productivity performance in electricity distribution. It is also possible that the parameters indicating the

[19] Such reporting may also be helpful in that it emphasises that managers of network businesses may sometimes be quite efficient given the policy environment they face.

productivity and cost impacts of policy settings are more statistically reliable than the efficiency estimates for any given business.[20]

The policy benefits from exploiting benchmarking models in this way have a long lineage. Indeed, where regulations and policies particularly affect business performance, this is sometimes the major reason for benchmarking.[21] Some of the impetus for regulatory reform of Australian utilities a decade ago arose from evidence about its beneficial impacts in overseas countries.

Interactions between policy and managerial inefficiencies may also be important

While it is important to distinguish managerial inefficiency from economic efficiency generally, it can be equally important to consider their interaction. Trade policy provides a well-understood illustration of the issue. Import tariffs have adverse impacts on efficiency by distorting people's consumption choices and diverting resources to industries that have a lower comparative advantage. That type of inefficiency need not involve any managerial inefficiency in that the business managers may still seek to minimise costs and set prices as efficiently as they can in the constrained world they face. However, tariffs may also have a dynamic effect on efficiency by lowering the incentives for managerial performance. This might occur because business managers feel insulated from competition or believe that governments will adapt tariffs (or provide subsidies) to maintain their business's profits regardless of their competitiveness. The managers may be intrinsically highly competent, but they respond to the incentives they face.

In the case of network businesses, the factors outside managers' control that may affect their managerial efficiency include, among other things, private or state ownership (and any associated issues with labour relations and governance), and the regulatory arrangements used to constrain monopoly profits. An enterprise has less pressure to rigorously test all investment and other spending options for its efficiency if it is partly shielded from the consequences of its decisions. This represents a form of 'moral hazard' of the kind that makes people less careful where they are insured against the consequences of certain risks.

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20 As an illustration, the parameter estimates of an OLS regression on productivity or costs will be unbiased regardless of the variance of the error terms (the error terms being the measures of business inefficiency). This is not true for any given business's efficiency measure.

21 This approach has been used across many industries and contexts, such as in electricity, rail freight, telecommunications, road freight, waterfront, coastal shipping, aviation and gas supply industries (BIE 1995), privatisation (Mota 2004), reliability and pricing (McLennan Magasanik Associates 2007), and international comparisons of stevedoring (PC 2003).

For instance, to the extent that an enterprise can link much of its spending to the imperative to meet reliability standards (thereby receiving regulated returns for its spending), then it has weaker incentives to control that spending. This is more likely where a reliability standard is not anchored to the customer value of reliability, and where the knowledge about how to achieve the standard lies mainly with the business, rather than the regulator. If the business is particularly sensitive to public perceptions of instances of unreliability then it may spend too much to reduce these risks, even if the standard did not require that. Moreover, as high reliability standards require greater capital expenditure, they provide a capacity for greater costs from inefficient management practices.

Once an external factor outside the control of the business also affects managerial efficiency, then fully controlling for that external factor in benchmarking analysis means that managers do not face the full incentives for efficient behaviour — subverting the goal of benchmarking.

Data problems

Any data inputs into benchmarking models are subject to error due to measurement problems, small differences in the definitions used by different businesses and the periods to which the data relate, and simplification of the relationship between costs, inputs and outputs. Businesses may not report reliable information. The AEMC pointed out:

> One regulator stated that the data provided by a service provider was so unreliable that it was difficult to conduct an independent audit of the data. (AEMC 2009a, p. 8)

Before the AER assumed responsibility as the distribution network regulator, state and territory regulators collected data on network businesses, but did not employ a common framework (AER sub. 13, p. 18). Lawrence (2009) notes that coverage of key variables such as opex has varied over time (p. v). Ergon Energy (sub. 8, p. 4) observed that the AER has only recently begun to implement consistent data collection. Such data limitations lay behind the AEMC's view that TFP methods could not yet be used to set x factors in CPI-x methods.

There are also significant data gaps. Some of the recent capital expenditure has reflected the need to replace assets close to their end of life (chapter 2; Topp and Kulys 2012), but data on asset vintages is incomplete.[22] More generally, a leading benchmarking practitioner (Lawrence 2009, p. 19) identified gaps in physical network data, which the AER is only now systematically addressing:

22 An observation also made by the AER in its justification for accepting substantial expenditure increases in various regulatory determinations.

> For instance, regulatory reporting guidelines deal almost exclusively with financial matters required for building block regulation with little or no mention on any physical system data. Thus, while they examine the moneys received and spent, and the financial characteristics of assets used, created and depreciated, there is no quantification of *what* assets are built, maintained or operated to deliver the network service. Jurisdictional regulators noted that their efforts to date had almost exclusively been directed at obtaining the financial data required for building blocks regulation and they had had little time to assemble data on physical characteristics and outputs.

Others point to the expedient use of easily available data for benchmarking, rather than the variables most suited to efficiency measurement (APA Group, sub. 2, pp. 1–3).

Nevertheless, *any* quantitative method is subject to error and data problems. The key question is whether it matters for the regulator's intended purpose (an issue to which this chapter returns). The MEU (sub. 11, p. 25) identified data limitations but — with some reasonableness — pointed to the fact that:

> There is a need for a consistent approach for the gathering, manipulation and display of data to make the best use of benchmarking. However, even imperfect data can provide useful insights and should not be excluded, even though its use might be minimised. … 'rough and ready' can provide a strong indication as to whether the proposed opex, capex and WACC outcomes are grossly inefficient and whether deeper analysis is required to ensure a more efficient outcome is possible.

Australia has few observations

There are only 13 distribution businesses, five regional transmission businesses and three separate direct current interconnectors in Australia.[23] This reduces the feasibility for more elaborate models that take into account the multiple environmental factors affecting inter-firm performance.[24] As the Consumer Action Law Centre argued:

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23 In contrast, Germany has nearly 900 distribution network operators (Schweinsberg et al. 2011, p. 29).

24 In a comprehensive survey of the use of benchmarking methods by individual countries, Haney and Pollitt (2011) argued that small numbers of network companies act as a constraint on the use of advanced benchmarking methods. The ENA observed that the greater the level of aggregation in the analysis, the greater the number of variables that should be included in the analysis, such as the type of street transformer, the distribution of asset vintages and climatic conditions (ENA, sub. 17, pp. 24–5). Of course, some factors that affect performance must be omitted from any benchmarking analysis given sample size limits. For example, an inefficient local government may be slow at processing planning proposals for a given network business, and no practical benchmarking approach can fully take account of such micro-factors. The extent to which a model should include variables must therefore depend on their materiality and statistical testing.

> However, with a relatively low number of network businesses to start off with, this may cause a particular challenge for the NEM that has been more easily overcome in overseas markets. (sub. 5, p. 4)

The case of interconnectors is even more problematic:

> In the case of 'single' electricity transmission assets such as Murraylink and Directlink, benchmarking is not an appropriate way to establish the price or revenue path. Their 'output' is the continued availability of full interconnection capability … These assets are unique and have no logical comparators on which benchmarking could be based. (APA Group, sub. 2, p. 2)

Given sample size problems, benchmarking is most likely to be effective in its application to distribution businesses (Grid Australia 2009), although Ergon Energy argued that even here, the numbers were too small to provide meaningful results (sub. 8, p. 3). The latter suggested that benchmarking reliability might be improved by including both transmission and distribution businesses in the analysis (sub. 8, p. 10).

Would international benchmarking help?

While international benchmarking might increase the number of observations, it raises other challenges for valid comparisons. For example, ETSA Utilities et al. (sub. 6, p. 27) and the ENA (sub. 17, p. 25) noted that results are affected by differences in exchange rates, reliability standards, accounting policies, tax laws and corporate structures.[25] The question of whether Australia has high, medium or low electricity prices — a potential test of efficiency — has proved difficult to resolve (Mountain 2012a in contrast to EUAA 2012). However, it appears that the results are sensitive to choices about the appropriate exchange rate and the retail tariff (regulated versus market rates). It merely serves to highlight some of the complexities of comparisons of this kind.

On the other hand, the Australian Academy of Technological Sciences and Engineering cited the value of the International Transmission Operation and Maintenance benchmarking (ITOMs), which is conducted every two years, covering about 30 businesses (ATSE, sub. 9, pp. 1–2). Australian transmission businesses are included in ITOMs and use it for internal purposes. ATSE also recommended the inclusion of Western Australia and the Northern Territory as comparators. While

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25 There was general opposition to international benchmarking by network businesses in both the Commission's informal consultations and in submissions made by them to this inquiry (for example, Ergon Energy, sub. 8, p. 9). However, as shown later, they do participate in international benchmarking for commercial reasons.

the MEU (sub. 11, p. 25) noted the difficulties of international comparisons, it considered that it could 'still provide some useful information'.

The Council of European Energy Regulators (2012) has undertaken extensive benchmarking of the quality of electricity supply — arguing that successive benchmarking analyses in this area may have prompted improvements in quality. However, even in this narrow area, it encountered significant differences in definitions, which complicated its benchmarking.

Overall, international benchmarking should not be dismissed, especially as the businesses use it themselves. However, it is likely to be most useful in specific aspects of the performance of the businesses where measures of physical inputs and outputs are available (such as reliability or certain labour productivity measures), for assessing business processes (such as the use of tendering and outsourcing) and for raising issues of concern that the regulator might pursue in further detail.

4.7 Other scientific criteria for judging benchmarking

While the validity of any benchmarking measure is a prerequisite for its use, there are also other criteria important for assessing the quality and interpretability of various benchmarks.

Accuracy and reliability

Accuracy is the degree to which a benchmark provides an unbiased estimate of efficiency, while the reliability (used here in the normal sense of reproducibility) is about the variance of the measure. For example, a bathroom scale that is consistently out by exactly 10 per cent is inaccurate, but reliable. As discussed above, a failure to adequately control for differences in operating environments can lead to heavily biased measures. More subtly, certain statistical models of productivity may use underlying assumptions at odds with the known properties of the variable of interest.[26]

26 For example, using ordinary least squares regression for categorical data (for example, yes/no answers, or ratings from one to five) will lead to biased estimates and a poor capacity for statistical inference.

Robustness

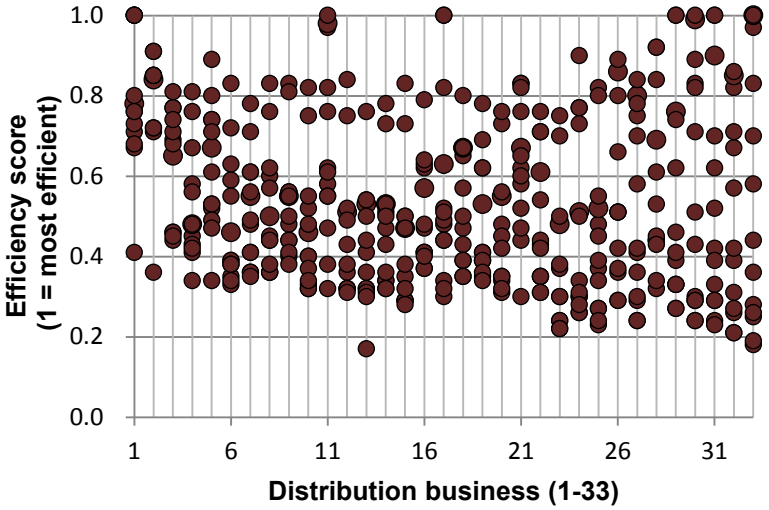
This is a subset of accuracy and reliability, but worth emphasising in its own right. A particularly useful robust measure is one that provides information about the efficiency of an enterprise regardless of its operating environment. Although affected by other kinds of errors, some measures of management performance (such as those underpinning figure 4.2) might fall into that category. However, such measures are likely to be the exception rather than the rule.

If the results of a model are sensitive to small perturbations in the underlying data, the addition of control variables with little expected impact, the removal or addition of a single network business, or to modest changes in assumptions and estimation techniques, then benchmarking results are at best indicative, and at worst, useless.

For example:

- Farsi and Filippini (2005) found that in a study of 52 distribution companies, the efficiency scores and rankings were significantly different across various methods, and especially between parametric and non-parametric models.
- A study of 33 Polish distribution businesses found a large dispersion in efficiency results for any given business (figure 4.10). These results would not be usable for regulatory purposes unless model specification tests were able to eliminate most of the models. This underlines the importance of testing.
- IPART's (2010) analysis of state-owned corporations, which included electricity networks, showed that the choice of input variables changed the rankings of firms and their TFP scores.
- The use of partial productivity indicators is also sensitive to specification. For instance, In their report to the WA Economic Regulation Authority, Wilson Cook (2009, p. 86) made several partial productivity comparisons between Western Power and network operators in other states. Three comparisons were made of distribution opex, separately accounting for customer numbers, line length (km), and electricity consumption (kWh). While these comparisons produced consistent *rankings* at a state level, they did not provide consistent measures of opex efficiency.
- Complex non-linear models appear to be particularly prone to problems. For example, in their review of European benchmarking of electricity networks, Schweinsberg et al. (2011, p. 55) found unstable convergence on parameters in stochastic frontier analysis (a common benchmarking approach), such that it was not possible to distinguish inefficiency from statistical noise.

Figure 4.10 **Estimates of inefficiency vary depending on the method**
Results for various measures of efficiency[a]



[a] The results are based on applying 14 benchmarking methods (variants of DEA, COLS and SFA) to 33 Polish electricity distribution businesses. Each vertical line shows the various efficiency measures corresponding to the 14 methods. (Often there will not appear to be 14 observations per business, because the measures sometimes coincide.)

Data source: Cullmann et al. (2006).

Limited susceptibility to manipulation or gaming

As in all systems where rewards and punishments depend on incomplete measures of performance, the measured party has incentives to 'look' like a highly performing entity (whether it be a hospital, school, a student, CEO, employee, or in this case, network businesses). As the Consumer Action Law Centre observed:

> It is thus important to be mindful of this when designing benchmarking mechanisms, but even more so when interpreting and applying the results. If given the opportunity, we can assume that the network businesses would seek to strategically influence the benchmark indicators and as such the result could be just another layer of 'gaming'. (sub. 5, p. 5)

Accordingly, the regulator should consider the capacity of any particular benchmarking measure to create unforeseen business behaviours:

- A benchmark measure might be a proxy for some hard-to-observe characteristic of efficient businesses or be sufficiently vaguely represented that firms can meet the benchmark, but not the underlying goal (CREG and SUMICSID 2011, p. 36). For example, a business may be able to meet some benchmarks by changing their cost-allocation methods (Jamasb et al. 2003), even if the underlying resource allocation is not optimal.

- The regulator also needs to consider the interdependence between some efficiency measures.[27] Measuring one aspect of efficiency (such as opex per kilometre of line), but ignoring another due to measurement difficulties (capital productivity), may result in inefficient substitution in distribution systems. This is one of the advantages of the CPI-x methodology and aggregate benchmarking.
- distorted information may directly affect the incentives of complying firms (NERA, appendix B of ENA sub. 17, p. 34).

Parsimony

A good model should be no more complex than required. This is important in assisting interpretability, avoiding data mining, achieving robust results, reducing data collection costs and allowing greater comparability of results across countries (since it is easier to ensure common definitions for a few variables).

An important facet of parsimony is to forgo complexity where it adds little explanatory power. For example, a Productivity Commission Staff Working Paper (Sayers and Shields 2001, p. 178) investigated the sources of price differences between Australian electricity distribution businesses, and found that many factors had small impacts. For example, at that time, the study found vegetation growth and its management had small impacts. (Whether that result remains true is uncertain, but the point is that it will sometimes be possible to identify factors that are largely immaterial for costs, and that can be eliminated as control variables.)

Similarly, in an exhaustive study of Belgium distribution network businesses involving multiple measures of outputs and inputs, the only relevant outputs were total circuit length of lines, customer numbers, and the total number of connections (CREG and SUMICSID 2011). One of the valuable aspects of international benchmarking analyses is they may be able to identify the variables that matter for networks more generally.[28] This may then allow greater confidence in using a small range of variables in the Australian context where the sample size is low.

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27 The ENA observed that the 'level of aggregation needs to be high enough such that material interdependencies between different expenditure types are captured in the analysis. For example, network augmentation expenditure on the sub-transmission system may be a substitute for augmentation expenditure on the distribution system and vice versa' (sub. 17, p. 24).

28 So long as there is sufficient variation in the cost drivers concerned (such as varying levels of forestation, wind, and temperature).

Fitness for purpose

As discussed further in chapter 8, benchmarking has multiple purposes. Some require great accuracy, reliability and robustness. This is particularly important where benchmarking is used to determine a business's revenue allowance. Such benchmark estimates should be highly reliable across time, business types and jurisdictions. The concerns are less where benchmarking is indicative — used to identify areas for possible future investigation, or to reach some prima facie judgment. This is how the Commission regards the preliminary results presented in chapter 6.

4.8 Testing the credibility of results

Benchmarking models do not actually estimate inefficiency, although this is how they are generally interpreted. The results of any benchmarking model show the extent to which the model *fails* to explain performance:

> … it is incorrect and misleading to ascribe the residual to 'inefficiency', or to describe the benchmark as a measure of 'efficient costs'. Instead, one must acknowledge that the residual measures no more than the element of observed costs that the model has failed to explain. (Shuttleworth 2005, p. 315)
>
> … an observation of difference does not itself constitute diagnostic evidence, the gold dust of effective assessment. (Yarrow 2012, p. 4)

That is, the inefficiency of any business is the difference between the business's observed performance and that predicted by a set of cost drivers. This can reflect missing cost drivers, data errors, incorrect estimation methods, and invalid assumptions about the functional form and error distributions.

The way of appraising the credibility of the results is through systematic investigation and reporting, including:

- explanation and graphical presentation of inputs and outputs and their main statistical features (averages, variances)
- divulgence of model selection processes, how data may have been manipulated, and why potentially relevant variables have been omitted
- comparisons with alternative models, and why the ultimately selected model(s) is superior to others
- tests of model adequacy, such as tests of linearity, normality or otherwise of the residuals, parameter stability with different sub-samples, the influence of outliers, and, subject to the caveats spelt out later, statistical significance

- Corroboration tests, which include assessment of the consistency in businesses' efficiency measures rankings based on different methods and over different periods. For example, if efficiency measures are reasonably stable over short periods of time, this increases the confidence in the results (since most businesses cannot improve their efficiency in very short periods of time).
- Explanation of what the results practically mean, and the possible flaws in the modelling.

The Commission examined a host of benchmarking studies. Very few undertook comprehensive testing of the models. This is acceptable where the results are 'indicative', but not where a regulator might use them to determine a business's revenues.

The capacity for statistical inference

This is probably the most neglected issue in interpreting various benchmarking measures, although essential to its meaningful use. This is why it is worth carefully dissecting.

Many people think of a benchmark as 'a' number. However, given the points made above, no model or measure is perfect. Accordingly, any benchmarking methodology should be able to identify a justifiable confidence interval around a predicted benchmark result. As an illustration, a benchmarking model might predict an efficiency score of 75 per cent for a given business compared with an industry average of 85 per cent (say the 'benchmark'). By themselves, these are not useful numbers. There are two broad ways of considering such estimates.

It is frequent for economists to argue that the difference between two estimates is, or is not, 'significant at the 0.05 significance level'.[29] The implicit notion is that 0.05 or some other lower probability that the difference could have arisen purely by chance somehow legitimises the value of the estimate. Under this approach, were the 85 per cent estimate to have a wide confidence interval then the regulator would be reluctant to use the 75 per cent estimate as a sign of genuine inefficiency for the business concerned (and probably be right in the context). On the other hand, if the confidence interval around the benchmark was very tight, they might regard 75 per cent as a reasonable measure of inefficiency for benchmarking.

However, this approach is often not useful in deciding what policy action to take (McCloskey, 1985a and McCloskey and Ziliak 1996, 2008). The appropriate

[29] The interpretation of such a statement is that the probability that the estimate is truly different from zero (or some other favoured null hypothesis) is 95 per cent.

framework to use is the so-called 'loss function', which considers the costs of errors around any point estimates. This is not esoterica — failing to do this can have major adverse effects on the economic efficiency and the distributional impacts of regulatory policy. Part of the reason that the Rules were designed in their current form was the view that making an error that led to lower investment would be more costly than the alternative. An international review of benchmarking methods and their practical application observed:

> The principal disadvantage of benchmarking is the potential that a model of poor quality can expose utilities to undue risk. While regulation must protect consumers from monopoly abuses, it must also not compromise the financial viability of regulated entities. … regulatory opportunism that violates the [the need for the utility] to raise funds, operate successfully and reward its investors for the risk they assume, must be prevented. (Lowry and Getachew 2009, p. 1325)

Biggar has questioned whether the costs of errors lie in this direction (as discussed in appendix B), but accepts that the costs of errors is an important one, a perspective that is unrecognised in many benchmarking studies.

These issues have several key implications for any benchmarking practices where the regulatory stakes are high, such as determining revenue allowances:

- The regulator should test assumptions about the nature of the distribution around a benchmark estimate. It is common to assume errors are normally distributed, though in practice, this is impossible for some benchmarking measures. For example, any simple regression — say of opex against customer numbers — cannot have normally distributed errors, because opex cannot be negative. That may not matter much in many applications, but it will in some.[30]
- The regulator should attempt to estimate, or at least make explicit its assumptions about, the loss function it believes is reasonable. That is not a trivial exercise, but at least transparent assumptions would be a useful step.
- Consultation with independent engineering experts with good knowledge of network business operations can help provide a basic credibility test of model results or of assumptions by parties not familiar with the actual operations of businesses. Similarly, as Pollitt (2005, p. 283) notes, as much as possible, it is desirable to test the consistency of a business's benchmark with financial market perceptions of its relative performance. The 1986 Challenger Shuttle disaster provides a graphic illustration of the potential divergence between expert engineering advice and hunches or statistical misunderstandings. NASA management claimed that the chance of a catastrophic failure of a shuttle was

30 A preferable approach would be to consider the likely distribution (for example, log normal) or to data-intensive methods in inference, such as bootstrapping (Varian 2005).

1 in 100,000 based on misinterpretations of safety factors and unjustified optimism. The engineers thought it was between 1 in 50 and 1 in 100 (Feynman 1986), a verdict that was found to be more compelling. It is quite conceivable that over-confident benchmarking modellers might make errors analogous to this — at least in terms of the consequences for a business (or consumers). This suggests the importance of engineering and financial analysis as a supplement in interpreting statistical benchmark results (and one of the reasons that the AER needs further resources to access such expertise).

Explanation of inefficiencies

Surprisingly, this is a rarely mentioned aspect for evaluating alternative benchmarking models,[31] and yet one of the most crucial for policy (and management purposes). Even if the measured inefficiencies of various businesses are regarded as accurate, it leaves open the question of why some businesses are managed less well than others. Some of the factors that may be relevant include the use of obsolete technology, little innovation, weak corporate governance or the form of ownership. If a benchmarking model can credibly unearth the behaviours that lead to managerial inefficiency, it corroborates the measures of inefficiency, and is useful for the businesses themselves. As Berg notes: 'performance rankings are … catalysts for promoting critical thinking about the sources of inefficiency' (2010, p. 54).

4.9 No perfect measure is possible

Benchmarking is a demanding quantitative (and qualitative) task. As in many other cases of firm-based modelling, the results are often fragile to data errors, statistical assumptions and variable choices. Prima facie, this appears to doom benchmarking as a useful tool, at least for the time being. However, this is overly pessimistic:

- criteria (such as those above) can be used to separate poor from better benchmarking
- it is possible to address inaccuracy and unreliability in using benchmarking (applying the loss function principles spelt out previously)
- regardless of whether satisfactory aggregate benchmarking models can be estimated, benchmarking will often still be useful for specific performance measures (such as the efficiency of vegetation management or the use of tendering)

31 Berg (2010, p. 54) is a notable exception.

- improvements in data collection are likely to improve benchmarking models
- it may have a role in policy-relevant areas other than revenue determinations (section 4.6 and chapter 8).

5 Incentive regulation and benchmarking

Key points

- Incentive regulation is a commonly used technique in the management of natural monopolies. It is designed to limit the business's ability to exercise market power, while maintaining the productive efficiency of a natural monopoly.
- Incentive regulation is applied to network businesses in the National Electricity Market using the building block approach to determine an allowable level of revenue. Firms that spend less than forecast are allowed to keep a proportion of the savings. There are also targeted incentives to promote specific goals, such as reliability and demand management.
- Under current arrangements, network businesses face weaker incentives to reduce capital expenditure as the regulatory period progresses. Introducing an efficiency benefit sharing scheme that applies to capital expenditure would result in more consistent incentives to reduce capital expenditure both over time and when compared with operating expenditure.
- Incentives for cost minimisation could also be strengthened by improving the estimate of the weighted average cost of capital (WACC) used in the regulatory process by:
  - using a long term trailing average to estimate the debt risk premium and the risk free rate
  - considering the interdependency of WACC parameters in both the determination and the appeals process
  - ensuring that state–owned network service providers obtain financing (both debt and equity) at rates that reflect the risk of the investment.
- By enhancing the information available to regulators, benchmarking can improve the effectiveness of the regulatory process. However, the value of this tool depends heavily on whether the incentive regulation arrangements allow its effective use.
- The extent to which the Australian Energy Regulator (AER) is restricted in applying different techniques, including benchmarking, as part of the building blocks process is disputed. While there is limited evidence that the AER has in practice been significantly restricted by the existing arrangements, there would be value in the Australian Energy Market Commission clarifying that the AER can substitute its own preferred estimate of capital and operating expenditure through a rule change.

Incentive regulation can be a useful tool for encouraging network businesses to minimise costs and implement cost-reducing investments aimed at improving the operating efficiency of a network. As discussed in chapter 4, benchmarking can assist in this process by enhancing the information available to regulators. However, the value of benchmarking to the regulatory process is dependent on how well the process of incentive regulation is working. A benchmark, no matter how accurate, is of little value if the regulator is unable to use it or if it does not influence the behaviour of the regulated firm.

This chapter briefly describes how incentive regulation works (section 5.1) before examining how it is applied to Australia's National Electricity Market (NEM) (section 5.2). Section 5.3 looks at the effectiveness of the incentives under current arrangements while section 5.4 discusses whether the AER is currently constrained in applying benchmarking.

5.1 Incentive regulation

The regulation of electricity networks involves a complicated problem. On the one hand, it is important to stop a network business exploiting its natural monopoly position by setting excessively high prices. On the other hand, retaining strong incentives for network businesses to pursue profits is important to drive efficiency in production and management decisions. Incentive regulation is designed to balance these goals by attempting to align the commercial goals of the business to the goals of society — efficient, reliable and low cost electricity supply.

Incentive regulation is a commonly used technique in the management of natural monopolies. While there are many different forms of incentive regulation,[1] a common theme is that they specify a goal, such as maintaining network reliability, and an estimated budget. If the business can outperform the predicted budget, it can keep a proportion of the savings, with the remainder passed through as lower prices for end users. The larger the proportion of savings that network businesses are allowed to keep, the stronger (or more 'powerful') the incentive regime is said to be. This approach contrasts with rate of return regulation (box 5.1), which does not reward cost minimisation or innovation, but nonetheless has some advantages in certain contexts.

[1] Vogelsang (2010) and Joskow (2008) provide a more detailed discussion of incentive regulation.

Box 5.1 **Rate of return and incentive regulation**

Pure rate of return regulation specifies the return on capital that a firm is allowed to recover, regardless of its performance. This ensures that a regulated firm is unable to exploit its monopoly position through price gouging. However, it also means that there are low incentives to provide services efficiently or develop more efficient practices through innovation.

Rate of return regulation was historically the standard practice for regulating monopolies (Vogelsang 2002) and continues to be used in the United States.[2]

A common criticism of rate of return regulation is that it suffers from the Averch-Johnson effect — in which firms subject to rate of return regulation have incentives to overinvest to increase the capital base on which they are guaranteed a return. While this criticism has had a strong influence on the move away from rate of return regulation (Vogelsang 2002), there is little empirical evidence to support it (Joskow 2005a).

In contrast to rate of return regulation, incentive regulation allows businesses to profit by outperforming expectations. This provides a stronger incentive for the business to find productive efficiencies in its operations. However, it is more informationally demanding than rate of return regulation as the regulator must still set an expected level of performance that is neither too 'soft' (excessive rents) or too 'demanding' (insolvency of the business). If the regulator cannot obtain sufficiently reliable information on a business's costs (due to strong informational asymmetries between the regulator and the regulated business), it may be possible for the business to game the regulatory process by presenting information that leads to a high revenue allowance. In that case, rate of return regulation may achieve better outcomes.

Incentive regulation is used to partially overcome the information asymmetries between the regulator and the regulated business. Absent these asymmetries, it would be possible to regulate the monopoly business using 'optimal' prices, which could be set using either marginal cost pricing or Ramsey pricing[3] techniques (Vogelsang 2002). However, these conditions are rarely, if ever, met in practice.

Another important feature of incentive regulation is that it is based on high-level outcomes, such as yearly expenditure and network reliability. It is designed to leave the day-to-day decisions, such as project choice and the timing of asset replacement, to the networks.

2 However, the Energy Networks Association (sub. 43, p. 4) point out that rate of return regulation, as applied in practice, usually exposes businesses to some changes in costs and so does not correspond with pure rate of return regulation as described here.

3 Under Ramsey pricing, revenue is recovered by placing higher prices on consumers with more inelastic demand.

The incentive regulation framework is not the only mechanism designed to promote efficient network investment. Networks must comply with the regulatory test (distribution)[4] and the Regulatory Investment Test for Transmission (RIT-T) and may be further constrained in their investments by the broader planning framework There are also planning frameworks that can restrict the investment decisions of businesses. As a result, even if in a particular circumstance the incentive framework does not provide appropriate investment incentives, these other mechanisms may still facilitate good outcomes. The transmission planning framework and the RIT-T are considered in chapter 19.

The challenge of designing and implementing incentive regulation

Designing and implementing incentive regulation is a difficult process, and any incentive scheme must address several challenges. The first problem is that incentive regulation is simultaneously trying to achieve different and sometimes conflicting objectives. As Kaufmann (2006) said:

> Regulators have the unenviable task of attempting to achieve inherently conflicting objectives. One important regulatory goal is promoting efficient behaviour by regulated utilities. Regulators must also ensure that customers share in the benefits of realised efficiency gains, but transferring benefits to customers reduces companies' incentives to undertake actions that lead to efficiency gains in the first place. Regulators therefore face a trade-off in trying to create incentives for utilities to behave efficiently, while ensuring that customers share in benefits from efficiency gains. (p. 1)

As a result, increasing the strength of incentives has some negative consequences and there is no 'correct' strength of incentive.

Information asymmetries between regulators and the businesses are another key challenge. Regulators do not have complete information about businesses' actual costs, expenditures, demand and service quality, but they need to make judgments about what the 'efficient' cost might be and how long it should take a business to close any efficiency gap. As Joskow (2006) put it:

> Fully informed regulators clearly do not exist in reality. Regulators have imperfect information about the cost and service quality opportunities and the attributes of the demand for services that the regulated firm faces. Moreover, the regulated firm generally has more information about these attributes than does the regulator or third parties which have an interest in the outcome of regulatory decisions. (p. 3)

4 This will soon be replaced by the Regulatory Investment Test for Distribution (RIT-D), which is the subject of a draft rule determination (AEMC 2012c).

A third challenge is to maintain the relative balance of power between the regulator and the regulated firm. If the regulator has too few resources and too little discretion in its operation, it is likely that the regulated firm will use their informational advantage to push for higher prices and profits. If the regulator has too much discretion, there is a risk that it could set the price too low, either due to a lack of information or for political reasons (Yarrow et al. 2012). This could reduce investment below efficient levels.

Given these challenges, incentive regulation will necessarily be imperfect. Nevertheless, there are several features that such regulation should desirably have, including:

- neutral incentives for expenditure on capex and opex, as well as constant incentives over time. If this is not the case, firms have incentives to inefficiently substitute between the categories of expenditure
- incentives that ensure that firms can never profit by artificially increasing costs
- incentives for firms to maintain or improve service quality levels as well as to reduce costs. This ensures that improvements in efficiency are not at the expense of quality of service
- limits on the rents captured by firms, although some rents may be necessary to deliver other goals[5]
- a linkage between the strength of the incentives and the level of confidence regulators have in their forecasts of efficient spending (the more accurate the forecast the stronger the incentive can be)
- as simple a system as is practically possible, and that is well understood by all parties involved
- some certainty for businesses that investments (often with long life times) made will yield a reasonable return
- a system that improves over time. The regulatory process can be seen as a repeated game between the regulator and regulated firms. Over time incentive regulation should use the information revealed by firms to develop better forecasts of efficient expenditure. This will reduce the scope for firms to earn excessive rents and allow the regulator to apply stronger incentives for further cost reduction (section 5.3).

5 Yarrow (2011b) gives a number of reasons why a regulator may want to provide some rents when applying a regulatory regime. These include that a firm that earns a stable return is more likely to look to long-term payoffs and is less likely to engage in short-term opportunistic behaviour.

5.2 Incentive regulation and the electricity sector

The National Electricity Rules (the Rules) govern the operation of the NEM. The economic regulation of network service providers is described in chapter 6 (distribution) and chapter 6A (transmission) of the Rules. The details of the regulatory structure differ between distribution and transmission networks (with the specific provisions spelt out in box 4.2 in chapter 4).

The AER is responsible for regulating businesses' expenditures to ensure these are consistent with the national electricity objective of promoting efficient investment in, and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability, safety and supply.

The AER makes revenue determinations for regulated transmission and distribution businesses every five years (though the Rules permit it to make determinations for different periods). This process involves the AER forecasting the revenue requirements needed to cover efficient costs and provide a commercial return (based on operating (opex) and capital (capex) expenditures).

In keeping with incentive regulation (as set out above), businesses that provide network services at a lower cost than forecast can keep a proportion of the savings.[6] There are also additional incentive payments for achievement of other goals – or penalties for non-achievement – including the Service Target Performance Incentive Scheme (STPIS) payment for network reliability and the Demand Management and Embedded Generation Connection Incentive Schemes.

NSPs recover the revenue allowances from electricity customers through a variety of 'control mechanisms', including price caps and revenue caps (described below).

Calculating the maximum allowable revenue

The maximum allowable revenue that an NSP can recover is based on the 'Revenue and Pricing Principles' of the Rules, which state that:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.

6 However, the amount that a firm can gain (lose) from underspending (overspending) depends on a number of factors, discussed in section 5.3.

The costs that a network can recover are determined using the building block[7] approach (box 5.2).

Box 5.2 **The building block approach**

The building block approach is used to ensure that the expenditure of each NSP is appropriately amortised over time. As a result each NSP, given efficient expenditure practices and decisions, is adequately compensated for the cost of providing the network services to customers in the long run.

The building block model consists of two equations, which are known as the revenue equation and the asset base roll forward equation. These two equations are used to determine an allowed stream of revenues for each NSP for as long as it remains regulated. Ignoring any incentive rewards or penalties, these equations together ensure that the present value[8] of the allowed revenue stream is equal to the present value of the expenditure stream of the regulated firm.

The building block equations are as follows:

MAR = return on capital + return of capital + opex + tax + incentive scheme payments[9]

= (WACC * RAB) + D + opex + tax + incentive scheme payments

and

new RAB = previous RAB – depreciation + capex

where:

- MAR = maximum allowable revenue
- WACC = post-tax nominal weighted average cost of capital
- RAB = regulatory asset base
- D = depreciation
- opex = operating and maintenance expenditure
- capex = capital expenditure
- tax = expected business income tax payable

Source: Statement of principles for the regulation of electricity transmission services.

7 The building block approach does not apply to network augmentations in the Victorian transmission network, which are governed by an alternate set of arrangements that are described in chapter 15.

8 $1 of capex invested will return, in any period, a return on that money and/or a depreciation payment. When these payments are summed in present value terms, they should equal $1 (using the regulatory WACC as the discount rate).

9 Such as the Service Target Performance Incentive Scheme and the Demand Management and Embedded Generation Connection Incentive Scheme.

The main components of a network's recoverable costs are:

- operating and maintenance expenditure
- capital expenditure
- asset depreciation costs
- taxation liabilities
- a commercial return on capital
- incentive payments for reliability demand management and embedded generation.

Each of the building blocks must be estimated for the five years that follow.

Determining revenue allowances is a complicated and lengthy process with formal procedures beginning up to two years before the regulatory period begins. Regulated businesses are required to submit highly detailed proposals that detail the network plans for the following regulatory period, which are then scrutinised by the AER. The process also involves input from consultants and other interested stakeholders.

Forecasting capital and operating expenditures

The building block process requires estimates to be made of the operating and capital expenditure required to operate a network for the following five years. This requires assumptions to be made about the efficient costs of running a network business, as well as projections of future demand and required network expansion.[10]

The revenue determination process follows a 'propose-respond' approach in which a network business develops a detailed plan and proposes the capex and opex it requires, with the AER responding to the proposal. The AER must either accept the plan if it *reasonably reflects* the costs of an efficient business or, if not, propose an alternative plan.[11]

In the case of distribution, the AER is further constrained by clause 6.12.3(f) of the Rules, which states that the new proposal must be based on the original proposal of the Distribution Network Service Provider (DNSP) and must only be altered to the extent that it makes the proposal reasonable.

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10 Which can be influenced by efficient network pricing, as discussed in chapter 11.

11 The Rules, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

The Energy Users Association of Australia argued that the propose-respond approach encourages NSPs to put forward ambit claims:

> This arrangement provides very strong incentives for NSPs to propose the highest possible level of expenditure during the regulatory control period that they think the regulator will accept. They can be expected to do that, partly out of their interest in minimising the risks that they face that they will not be able to meet reliable supply objectives without jeopardising financial performance targets, and partly also out the knowledge that higher allowed expenditure levels translate into higher allowed revenues and thus better financial performance. (sub. 24, p. 5)

Whether the AER has enough power to scrutinise the proposals made by NSPs, including through the use of benchmarking, is discussed in section 5.4.

The weighted average cost of capital

The weighted average cost of capital (WACC) is the rate of return required by investors to induce them to commit funds to the NSP (box 5.3).

There are two sources of funding, or capital, for businesses — debt and equity. For both sources, there are costs — interest must be paid on debt, and those providing equity expect a return on their investment commensurate with the higher level of risks that an equity provider faces. The WACC for any firm is determined by the return that it pays on debt and equity, weighted in accordance to their relative use.

As part of the building block process (revenue determination), the regulator needs to estimate the WACC of an efficient network business. It is an *estimate* of the actual financing costs of network businesses and is used to determine the revenue allowance that network businesses may recover. For clarity, this estimate is referred to as the regulatory WACC, while the actual capital costs that businesses face to fund their investments is referred to as the 'actual' WACC.

The regulatory WACC is set with reference to the efficient financing costs of a generic network business. The individual circumstances of any particular firm are not considered when calculating this WACC. This creates incentives for businesses to source debt and equity financing efficiently, while considering the financial risks associated with different financing strategies.

The impacts on incentives of having an incorrectly specified WACC are discussed in section 5.3.

Box 5.3 **Calculating the WACC**

The WACC is calculated by weighting the returns to debt and equity in the proportion that these financing sources are used:

$$\mathrm{WACC} = \mathrm{k_e}(1-T)\,{}^{\mathrm{E}}\!/_{\mathrm{V}} + \mathrm{k_d}[\frac{1-T}{1-T(1-\gamma)}]\,{}^{\mathrm{D}}\!/_{\mathrm{V}}$$

Where k_e is defined as the return on equity, k_d as the return on debt, and E/V and D/V are the weights in which debt and equity financing are used.[12] T is the corporate tax rate and γ (gamma) is the proportion of imputation credits that can be used by shareholders.

The return on equity is calculated as:

$$\mathrm{k_{e=}r_f} + \beta_\mathrm{e} \times \mathrm{MRP}$$

Where r_f is defined as the risk-free rate, β_e is the firm specific equity beta and *MRP* is the premium per unit of market risk (calculated using the capital asset pricing model).

The return on debt is calculated as:

$$\mathrm{k_{d=}r_f} + \mathrm{DRP}$$

Where r_f is the risk-free rate and *DRP* is the premium per unit of market risk.

Source: The Rules, clause 6.5.2

Incentive schemes

The current Rules require that the AER apply an efficiency benefit sharing scheme (EBSS) and a service target performance incentive scheme (STPIS) to transmission businesses.[13] In the case of distribution, the AER *may* apply a STPIS, an EBSS and a Demand Management and Embedded Generation Connection Incentive Scheme.[14]

The EBSS determines the way in which benefits of efficiency gains are shared between NSPs and network users, and attempts to provide incentives for efficiency that do not diminish over time. Presently, the EBSS only applies to opex. However, a current rule change request has proposed the introduction of an EBSS on capex. This is discussed in section 5.3.

12 As stated in the Statement of Regulatory Intent on WACC parameters, revenue determinations assume that D/V is equal to 0.6 and E/V is equal to 0.4 (AER, 2009b, p. 6).

13 The Rules, clauses 6.A.6.5 and 6A.7.4.

14 The Rules, clauses 6.6.2, 6.5.8 and 6.6.3.

The STPIS provides financial incentives for networks to achieve high levels of service performance (chapter 16). The Demand Management and Embedded Generation Connection Incentive Scheme provides incentives for DNSPs to provide non-network alternatives, including embedded generation, where these are efficient. In part, this scheme is designed to reduce the incentives that exist under a price cap for networks to encourage higher demand (though these incentives are imperfect — chapter 12).

Managing forecasting uncertainty

Expenditure forecasts are inherently uncertain as they include a wide range of assumptions about the cost drivers of network businesses. To create strong incentives for cost minimisation, businesses should, ideally, bear the consequences of poor management of the costs they control. However, for costs that are not under the control of a business there is a case for electricity users, rather than network businesses, to bear the risk of increases.[15]

For costs outside the control of the business, the regulator can allow the business to use a cost pass through, in which the some specific categories of costs are included in the revenue allowance without needing to be in the building block forecasts. Chapter 10 of the Rules defines pass through events to include:

- a regulatory change event
- a service standard event
- a tax change event
- a terrorism event.

In addition, TNSPs may consider a prescribed insurance event[16] as a pass through, while DNSPs may nominate additional events during its revenue determination.

A further mechanism for reducing uncertainty in revenue forecasts is the treatment of so-called contingent projects in revenue determinations. If it is unclear whether a project will be needed during the forthcoming period due to difficulty in forecasting demand and generator entry, a project may be entered into the revenue

[15] In the case of regulatory intervention, such as a tax change, cost pass throughs stop governments appropriating the value of a sunk asset.

[16] Defined in chapter 10 of the Rules, an insurance event occurs where either (a) the cost of insurance through premiums or deductibles is greater than 1 per cent of the maximum allowable revenue, (b) insurance is not available, or (c) the terms of the insurance arrangements change materially during the investment period.

determination as a contingent project.[17] This means that the business can only recover the costs of the project if a trigger event occurs. Currently, contingency provisions only apply to transmission projects. However, in considering the AER's recent Rule change request, the AEMC (2012a) has recommended the introduction of a contingent projects framework for DNSPs.

Applying the revenue allowance

The maximum allowable revenue calculated using the building block methodology is converted into prices using:

- a revenue cap by all TNSPs providers and by DNSPs in Queensland and Tasmania
- a weighted average price cap by DNSPs in New South Wales, Victoria and South Australia
- a maximum average revenue cap by DNSPs in the Australian Capital Territory.

A revenue cap control sets the maximum allowable revenue for each year of the regulatory control period. To comply with this revenue constraint, a business forecasts demand across different services for the next regulatory year and sets prices so that the expected revenue is less than or equal to the revenue cap. The business can recover more or less than the allowed amount, but knows that the maximum allowable revenue in future years will be adjusted for any difference between the expected and actual revenue of previous years (using an 'unders' and 'overs' account).

Under a weighted average price cap, prices are set so that NSPs will receive the maximum allowable revenue if the demand forecasts used to calculate the price caps are accurate. If demand turns out to be more than expected, the NSP will receive more than the maximum allowable revenue and if demand is less than expected, the NSP will receive less than the maximum allowable revenue.

A maximum average revenue cap puts a cap on the average revenue per unit of electricity sold (usually kWh). That average is calculated by dividing the maximum allowable revenue by the quantity of energy demanded from the most recent year available (rather than using a forecast as is the case with a weighted average price cap).

17 As described in schedule S6A.1.3 (10) of the Rules.

The rationale for the different methodologies between DNSPs is largely historical, reflecting the state-based arrangements that were in place prior to the AER taking over regulatory responsibility. The relative merits of different control mechanisms, and in particular their ability to assist in efficient network pricing, are discussed in chapter 12.

Incentives provided by the current rules

Despite the apparent complexity of the regulatory regime, the incentives provided to network businesses are relatively straightforward. To increase its level of profit in the period following a regulatory determination, an NSP must either:[18]

- underspend the capex or opex target
- obtain capital at a rate lower than the regulatory WACC (discussed in section 5.3)
- improve its performance in the incentive schemes, such as the STPIS
- have actual demand volumes greater than forecast volumes (if operating under a price cap)
- improve performance in other business activities that are treated as competitive and thus not subject to regulatory determinations.

The strength of the incentives, as reflected by the proportion of any cost reduction retained by the NSP, varies across each category, and across time within each category.

Also noteworthy is the fact that the regulatory regime does not make a distinction between the ways in which opex and capex reductions occur. This means that a business would be equally rewarded in the period following a regulatory determination for an equivalent cost saving from:

- finding a way to reduce construction costs
- finding an alternative cheaper project that achieves the same goal
- deferring a project into the next regulatory period.

As the incentives apply to the difference between forecast and actual expenditure, any incentive that is applied to cost reductions must also apply in equal strength to the motivation to push for increased capex and opex forecasts in the determination process. For example, if an NSP can increase the revenue forecast by $1 million by

[18] Based on the supplementary paper 'Power of Choice Review' (AEMC 2012b, p. 3)

challenging the AER's decisions through the limited merits review process, they will improve their measured performance (forecast minus actual spending) by the same amount as if they had cut costs by $1 million.

This creates a dilemma when setting the power of the incentive scheme. Regulators are likely to want to provide stronger incentives for cost minimisation in the production process than for project deferral, as a new project is still likely to provide some benefits to the network.[19] It is also undesirable to have strong incentives encouraging network businesses to attempt to increase the revenue determinations.

5.3 Effectiveness of incentives applying to capex

Several participants in this inquiry claimed that, under current arrangements, the incentives are not strong enough to encourage cost minimisation and may actually encourage firms to inflate costs. AEMO, for example, suggested that:

> The 'building block' method for setting network revenues creates an incentive to over-invest in network assets. The growth in capital expenditure over the past five years demonstrates the strength of the rewards for building assets. Jurisdiction by jurisdiction comparisons indicate that much of this expenditure is not required by the age of network assets or the growth in demand. (sub. 32, p. 4)

The Consumer Action Law Centre (sub. 5) and the Major Energy Users (sub. 11) made similar claims. The AER has sought a Rule change to address its perceptions of defects in the incentive regime. It maintained that, while there had been some legitimate motivations for rapid growth in investment in networks:[20]

> … what is not so clear is whether all these increases in investment are efficient. Concerns with whether the regime is promoting efficient outcomes and whether the incentive based nature of the regime works effectively across all businesses in the NEM has led the AER to seek some changes to the regime and to enhance its internal capacity to undertake comparative benchmarking of network businesses. (sub. 13, p. 7)

In contrast, many in the industry contest that there are any significant problems in network efficiency or the incentive regime.[21]

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19 Such as increased access for generators or reliability for customers.

20 It did, however, acknowledge that the historically high level of investment in the NEM in the current five-year regulatory cycle had also been driven by other factors, including load growth and rising peak demand, ageing assets requiring replacement and reinforcement capital expenditure and other obligations related to network security, safety and reliability.

21 For example, Grid Australia (sub. 44, p. 33) provides a critique of AEMO's position.

Establishing whether the current incentives have contributed to the inflation of operating costs or to 'gold-plating' is far from easy (chapters 4 and 6), and it is easier to determine whether the incentives are misaligned, than to show that the networks are exploiting this fact. As put by the Consumer Action Law Centre:

> To prove that network businesses are strategically 'gold-plating', underspending capex, deferring capex etc. in order to maximise their profits is almost impossible. Consumer Action's view is that rather than seeking evidence, the Commission (as well as other organisations such as the AEMC) should assess whether the distribution businesses have the opportunity to behave this way under the current framework, and if so, it should be assumed that a rational business would be seeking to maximise their profits. (sub. 5, p. 4)

To this end, this section looks in detail at the efficacy of incentives under current arrangements and how those incentives might be improved. Many of the ideas and proposals raised are already the subject of ongoing rule change deliberations, especially in the context of the AEMC's consideration of the AER's 2011 Rule change request (AEMC 2012a).[22]

Incentives to reduce capex diminish over time

The financial incentives provided for outperforming (underspending) the capex target depend on:

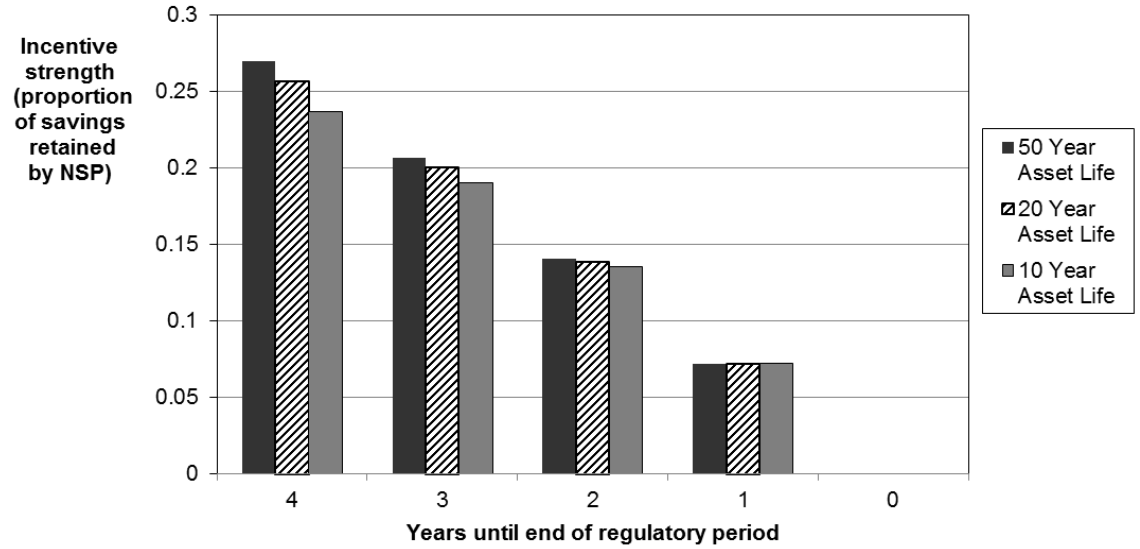
- the year in which the saving is made
- the asset life of the capital project
- the difference between the regulatory WACC and the NSP's actual cost of capital.

As shown in figure 5.1, the incentive to reduce capex declines throughout the regulatory cycle.[23] The value on the vertical axis represents the increase in the net value of the business from reducing capex spending by $1. As an example, reducing capex spending by $1 in the first year of the regulatory period yields a profit (in net present value terms) of around 25 cents for an asset with a 20 year life. As the incentive system is symmetric, this figure can also be interpreted as the cost to a business of increasing spending by $1.

[22] The AER (and the Energy Users Rule Change Committee) requested a Rule change (AER (2011a) and EURCC (2011)). This is generally referred to as relating to the *Economic Regulation of Network Service Providers*. For simplicity it is referred to as the AER's Rule change request throughout this chapter.

[23] A similar calculation can be found in AER (2011a, p. 40).

Figure 5.1 **Capex incentives vary across the regulatory period**



a Commission calculations based on assumptions including both the regulatory WACC and the actual WACC are equal to 9 per cent. The value on the vertical axis represents the increase in the net value of the business from reducing capex spending by $1. As an example, reducing capex spending by $1 in the first year of the regulatory period yields a profit (in net present value terms) of around 25 cents for an asset with a 20-year life.

The calculations reveal that businesses face weaker incentives to reduce capital expenditure as the regulatory period progresses, although in the scenario shown, there is always some incentive to reduce capex spending. However, businesses that face other incentives — such as pressures to improve reliability or risk aversion to underbuilding — may well err on spending above an 'efficient' amount, especially as a regulatory period comes close to its end.

Incentives that change across the period in this way are can be problematic. As well as creating incentives for NSPs to defer spending from early in the regulatory period, when the reward from reducing spending is higher, to later in the period, when the penalty for overspending is lower, they may also encourage substitution between capex and opex (box 5.4).

Box 5.4 **An example of capex opex substitution – ageing assets**

Ageing assets require more monitoring and maintenance than new assets. Therefore, the decision to replace an old asset involves a trade-off between the upfront capital cost of replacement and the ongoing costs of maintenance. Ideally, an NSP will replace the asset at the time that minimises the net present value of the associated costs.

In the last year of the regulatory period, a NSP has weak incentives to reduce capex, while its incentives to reduce opex are still relatively strong due to the efficiency benefit sharing scheme applying to this component of expenditure. In this situation, the trade-off faced by NSPs is distorted, and they may inefficiently bring forward capex spending.

The extent to which networks actually shift capital spending over the regulatory period or substitute between capex and opex is unclear. Network projects are often planned years in advance. There are other levels of regulatory oversight, such as the regulatory test and RIT-T, that could make it difficult to change the timeframe of a project. There are also accounting standards that limit the way firms can capitalise expenditure. However, as shown in figure 5.2, the empirical evidence is that overspending (spending more than the forecast amount) tends to increase later in the regulatory period.

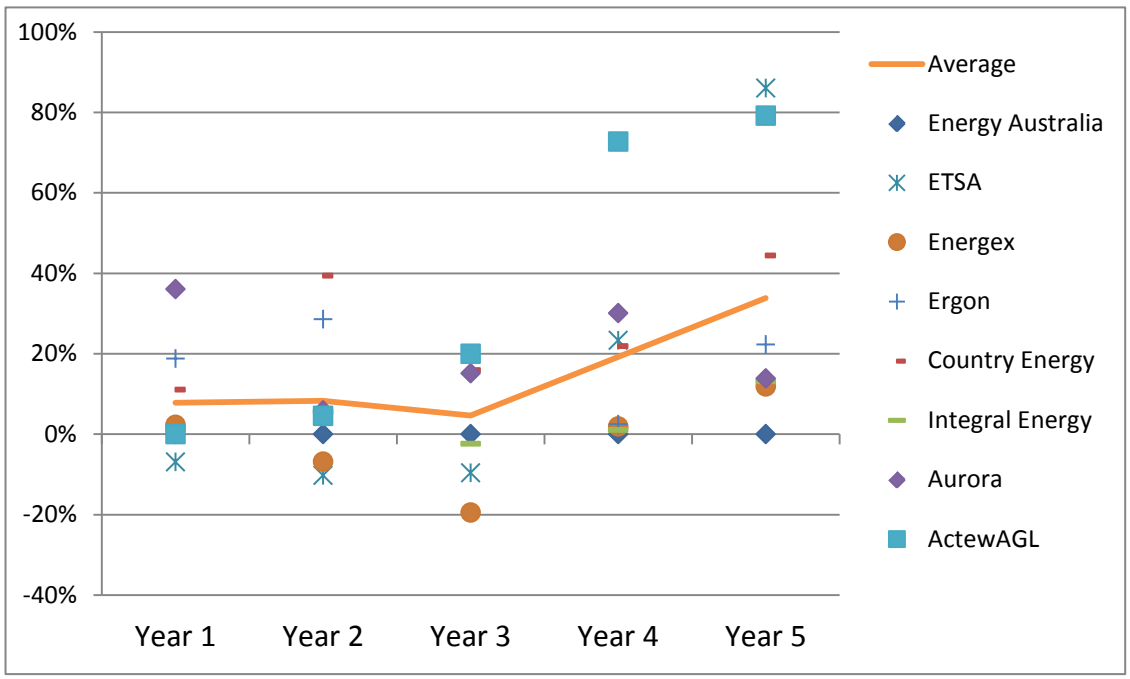
Given the various factors that determine the incentive to reduce capital expenditure, there are several ways that the incentive structure could be changed to provide more consistent incentives throughout the regulatory cycle. One possibility is the introduction of an efficiency benefit sharing scheme (EBSS) for capital expenditure, as currently exists for operating expenditure.[24]

An EBSS for capex would allow NSPs to retain a given proportion of any efficiency gains made by reducing or deferring capex.[25] If designed correctly, it would also provide a constant incentive over time to pursue such savings and, if the incentive rates were set the same between expenditure classes, remove any incentive to substitute between capex and opex. Firms that were considering investments that improved reliability and, thereby, generated increased returns through the STPIS would also face more consistent trade-offs under an EBSS than under the existing arrangements.

[24] The current rules allow the AER to develop an EBSS for capex for distribution networks but it has not exercised this ability. Introducing an EBSS for transmission would require a rule change.

[25] The existing EBSS for opex allows firms to retain the benefits of an efficiency improvement for five years, after which the improvement is incorporated into the revenue calculations. For example, if a efficiency gain is made in year three of the regulatory period, the revenue allowance will not adjust to incorporate this until year three of the next regulatory period.

Figure 5.2 **Overspending tends to increase later in the regulatory period**



a Each symbol denotes a distribution network business. The vertical axis shows the ratio of (actual capex – forecast capex) / forecast capex. Cost pass throughs are considered as part of forecast capex. Data are from the last completed regulatory cycle. Victorian networks are excluded from the analysis due to the capex efficiency carryover mechanism that applied at this time.

Data source: Parsons Brinckerhoff (2009a, 2009b, 2010, 2012); Wilson Cook and Co. (2008).

An EBSS for capex is currently being considered as part of the AER rule change proposal (AEMC 2012a) and has been considered previously by the AER (2008b). Some technical issues would need to be addressed before any such scheme was introduced. For instance, the AER's decision in 2008 not to pursue the approach was predicated on concerns that projects could be included in more than one forecast, and as a result, that an EBSS would provide overly strong incentives to defer projects between periods.[26] Care will also need to be taken to ensure that the introduction of an EBSS is done in a way that complements other aspects of the incentive regulation framework such as the STPIS and the Demand Management and Embedded Generation Connection Incentive Scheme. However, there is experience of capex sharing schemes that have worked, both in Australia and overseas, suggesting that any implementation problems are not insurmountable (AEMC 2012a).

26 To successfully implement an EBSS for capital expenditure, it is necessary to distinguish between expenditure that has been saved, through more efficient construction or planning outcomes, and expenditure that has been deferred. If spending that is deferred between periods is included in the next regulatory determination as a new project, it may appear that the entire project has been avoided and the costs counted as long-term savings, for which the networks will receive a large payment.

DRAFT RECOMMENDATION 5.1

The Australian Energy Regulator should develop an efficiency benefit sharing scheme to apply to capital expenditure that provides consistent incentives to reduce capital expenditure, both over time and when compared with operating expenditure.

Incentive effects when the regulatory and actual WACC are different

The building block process requires the estimation of the efficient return on capital of a network business. If this estimate is equal to the actual cost of finance for a regulated business, that business should be indifferent about the size of their RAB. However, if there is not equivalence, the regulated WACC will have an impact on the incentives of NSPs to invest.

These impacts depend largely on future expectations. Given the typically long lives of their assets, network businesses' return on capital expenditure depends on the WACC determinations over many regulatory periods.[27] Hence, a short-term expected difference between the regulatory WACC and the actual WACC is likely to have only a small impact on long-term investment decisions. However, it would result in a wealth transfer between consumers and producers of electricity. If the regulatory WACC is too high, prices would be higher than otherwise, and the transfer would be from consumers to producers (and vice versa if the WACC is too low).

As discussed in chapter 3, while the allocative inefficiency effects of transfers are modest in the short term, they still matter in other respects, and transfer to producers from setting the WACC too high would potentially not be consistent with the National Electricity Objective. On the other hand, while setting the regulatory WACC too low would lower prices to end users in the short run, it might make it difficult for firms to recover their efficient costs in the long term. This would contravene the revenue and pricing principles of the National Electricity Law, and in any case would not be in the *long-term* interest of consumers.

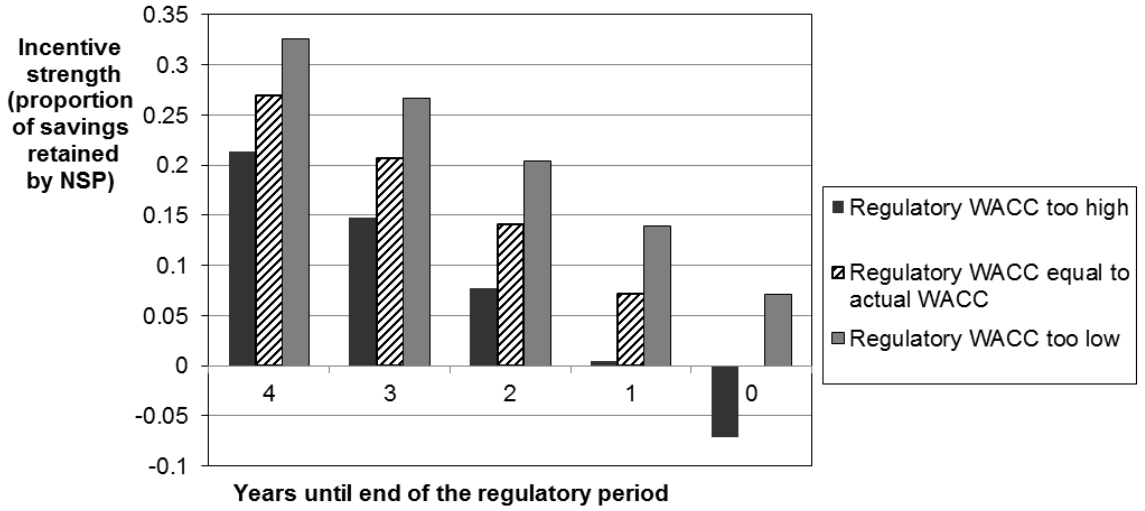
If NSPs expect a long-run positive divergence between the regulated and actual WACC, it can create incentives for businesses to over-invest. While the business would not receive any revenue allowance for any investment above the agreed regulatory forecast during the initial regulatory period, under the current Rules, the assets would be rolled into the RAB at the commencement of the next regulatory period. The business would receive returns for the remaining (typically long) lives

[27] A point made by the Energy Networks Association (2011a, p. 30).

of the assets. If the WACC is sufficiently high, then over-investment may be profit maximising.

Figure 5.3 shows the strength of the incentives throughout the regulatory period if the regulatory WACC is 0.5 per cent above or 0.5 per cent below the actual WACC. As was the case for figure 5.1, the value on the vertical axis represents the increase in the net value of the business from reducing capex spending by $1. As shown in the diagram, having a regulatory WACC that is too low will strengthen the incentive to reduce costs, while a regulatory WACC that is too high will weaken this incentive.

Figure 5.3 **Impact of error in the regulatory WACC**



a Commission calculations. Assumes an asset life of 50 years and an actual WACC of 9 per cent compared to a regulatory WACC of 8.5 per cent in the low case and 9.5 per cent in the high case. As was the case for figure 5.1, the value on the vertical axis represents the increase in the net value of the business from reducing capex spending by $1.

In the first few years of the regulatory period, the cost saving incentives in the building block regime outweigh the incentives provided by an overly generous WACC and result in net incentives to decrease expenditure. However, the incentives to reduce capital expenditure diminish throughout the period and at the end of the period, there is potentially an incentive to over-invest.

Is the regulatory WACC higher than the actual WACC?

It is difficult to compare the actual cost of capital with the regulatory cost of capital due to issues in measuring costs of equity.[28] However, it is possible to compare the actual borrowing costs of firms with the forecast cost of debt used in the revenue determination (table 5.1).

Table 5.1 **Comparing the regulatory cost of debt with actual borrowing costs**[a]

NSP	*Regulatory cost of debt*	*Actual cost of debt*	*Difference*
	%	%	% points
Citipower	8.81	8.17	0.64
Powercor	9.35	8.17	1.18
SP Ausnet (distribution)	9.19	7.52	1.67
ETSA Utilities	8.87	8.10	0.77
Aurora Energy	8.00	6.50	1.50
Ergon Energy	8.98	7.48	1.50
Energex	8.98	5.94	3.04
Essential Energy (Country Energy)	7.77	7.48	0.29
Ausgrid (Energy Australia)	7.77	7.03	0.74
Endeavour Energy (Integral Energy)	7.84	7.55	0.29
Powerlink	8.10	6.98	1.12
SP Ausnet (transmission)	8.20	5.99	2.21
Transend	7.79	6.14	1.65
Transgrid	7.78	6.63	1.15

a The actual cost of debt is taken from the annual reports of the network businesses. It is an average, reflecting the five most recent years available and is calculated as a business's finance costs as a proportion of its interest bearing short and long term liabilities. The level of liabilities is estimated by averaging the liabilities at the beginning of the period and the end of the period.

The average regulatory cost of debt is 1.25 per cent higher than the realised borrowing costs, which equates to a WACC that is 0.75 per cent higher than the actual WACC. Care should of course be taken in interpreting such a figure as the numbers are based on a number of simplifying assumptions and abstract from some of the complexities of financial markets.[29] Moreover, a similar calculation performed by the Energy Users Rule Change Committee (EURCC 2011) has drawn a number of responses that provide, at least in part, an explanation for the apparent

28 The return on equity is determined by investors' expectations of future returns, which can only be partially observed through the experienced return and cannot be measured reliably.

29 The calculation uses data from the end of the financial year, which may not be typical of the rest of the year. The calculations also abstract from issues such as short versus long-term financing and refinancing risk.

differences.[30] However, even considering these factors, the Commission believes there is some suggestion that NSPs may have been overcompensated for the cost of debt in recent years.

Improving the regulatory WACC

Since the AER has taken over the economic regulation of NSPs, the regulatory WACCs have increased. Two possible reasons for this are:

- financial conditions have changed, particularly for those NSP determinations during periods affected by the global financial crisis
- the framework for calculating the WACC, and disputing the results, has changed.

Both factors are likely to have been influential. It is important to examine the ways in which the regulatory process has changed, and only retain changes that have improved the accuracy of WACC estimates.

A rigid determination approach

The regulatory arrangements for determining network revenue allowances under the Rules are prescriptive in the way that components of the revenue determination can be calculated. As a result, the elements of the WACC discussed in box 5.4 have often been calculated in isolation and important interrelationships have been ignored, including those between the:

- debt risk premium and the risk free rate
- market risk premium and the risk free rate
- market risk premium and the utilisation of corporate tax credits
- market risk premium and the equity beta.

While there is nothing in the Rules that currently precludes the consideration of such interrelationships, actual practice appears to have underplayed such linkages. Thus in their joint submission, ETSA Utilities, Citipower and Powercor argued that:

> The AER appears to have placed too much weight on bottom-up benchmarking of individual WACC parameters, and too little weight on the inter-relationships between WACC parameters and on overall checks of cost of equity and cost of debt. (sub. 6, p. 40)

[30] In particular, networks have argued that businesses have been forced to borrow funds with a shorter date to maturity, and that the lower cost of debt has been offset by an increased refinancing risk. A summary of these responses can be found at AER (2012c, p. 55).

The Queensland Treasury Corporation concurred, though it acknowledged the practical difficulties in formalising these inter-relationships in the Rules:

> Any time there is a change in one parameter, each of the other parameters should be checked to ensure that any follow-on effects are taken into account. However, although there is likely to be some agreement about which relationships exist, we consider it would be quite difficult to reach an agreed formulation of these relationships for inclusion in the Rules. (sub. 12, p. 4)

The Commission agrees that it would be difficult to build interrelationships into the Rules in a formulaic manner. However, it is important that linkages between the parameters are considered in the determination process. Therefore, any consideration of the WACC should take a holistic approach, rather than attempting to estimate each parameter in isolation. This need should also be reflected in determinations made by the Australian Competition Tribunal on any appeals made by businesses or other parties, a point which will likely be covered in the current examination of the limited merits review regime (Yarrow et al. 2012a).

DRAFT RECOMMENDATION 5.2

The National Electricity Rules should specify the interdependent nature of the parameters used to estimate the weighted average cost of capital, and specify that any merit review must also consider the relevant rule in that light.

Exposure to short-term conditions in the debt market

Currently, within the Rules, both components of the cost of debt — the risk free rate and the debt risk premium — are observed in the market. Although, the Rules specify that the risk free rate be evaluated through the use of a moving average, this average rate is appraised over the short term. The debt risk premium is similarly appraised over the short term in order to maintain consistency across the components of the cost of debt.

Using short term averages to determine the cost of debt exposes businesses and customers to the risk of unusual market circumstances during the averaging period, of which the global financial crisis is the most recent compelling example. Firms that had revenue determinations in the immediate aftermath of the crisis had high borrowing costs built into the WACC for the following five years. The AER estimate that setting the debt risk premium at a level closer to the actual borrowing costs of businesses would have lowered electricity prices by $400 million in 2011 (AER 2011a, p. 65).

Averages taken over a longer period — such as a five year trailing average — are more stable predictors of market conditions and are more likely to represent the

actual borrowing patterns of the firms involved, as no firm would normally roll over its entire debt portfolio in a two week period every five years.

The AEMC has considered this issue in response to the AER rule change proposal (AEMC 2012a). Its interim conclusion is that the AER should use a longer-term average to determine the DRP and the risk free rate. However, the AEMC argues that there are several ways of implementing this principle and that the AER should have discretion to choose how to apply it. The Commission supports this approach, provided that the AER, in doing so, considers how this will affect the incentives for NSPs to raise funds and manage risk efficiently.

DRAFT RECOMMENDATION 5.3

Estimates of the debt risk premium and risk free rate used in the calculation of the weighted average cost of capital should be calculated using long-term trailing averages.

Limited merits review

In 2008, a limited merits review regime was introduced into the National Electricity Law. It is designed to help ensure that decisions made by the AER are appropriate and thereby to provide confidence and security to investors in the network businesses.

Many of the limited merits reviews have focused on the WACC and have resulted in substantial increases in the revenue determinations (table 5.2). The figures should not be interpreted as necessarily indicative of inefficient increases in determinations, as the AER may well have underestimated the correct WACC in some instances. Regardless, they underline the financial importance of the limited merits review process.

Table 5.2 **Limited merits review decisions regarding the WACC**[a]

Business	*Year*	*Focus of review*	*Increase in revenue allowance*	*Increase as a percentage of allowed revenue*
			$ million	%
Integral energy	2009	Risk free rate	338	9
Energy Australia	2009	Risk free rate	945	11
Country Energy	2009	Risk free rate	467	8
Transend	2009	Risk free rate	80	8
Transgrid	2009	Risk free rate	374	10
Energex	2010	Gamma	288	4
Ergon	2010	Gamma	200	3
ETSA	2010	Gamma	246	6
SPI Ausnet	2011	Gamma & DRP	31	1
Citipower	2011	Gamma & DRP	31	3
Powercor	2011	Gamma & DRP	58	2
United Energy Distribution	2011	Gamma & DRP	41	2
Jemena	2011	Gamma & DRP	31	3
Total			3183	8

a DRP is the debt risk premium (discussed above), Gamma is the assumed utilisation of imputed tax credits

Source: CME (2012).

In 2012, the Standing Council on Energy Resources (SCER) appointed a panel to undertake an examination of the limited merits review regime. The limited merits review panel has observed that the process has not worked as intended. Its stage one report found that:

> … the regime has failed to address the realities of regulatory decisions summarised in this ARC statement. Instead, a narrower, more formalistic and more formulaic approach to review has developed, which has been relatively detached from the promotion of the objectives set out in the NEL … and particularly from the requirement that regulatory decisions be directed toward encouraging outcomes that are in the long term interests of consumers. (Yarrow et al. 2012b)

One key concern regarding the current operation of the limited merits review process is that network businesses have a capacity to 'cherry pick' the aspects of a proposal where they believe the regulator is in error. In contrast, they obviously have little interest in revealing where the regulator has been too generous. In some instances, this has led to the situation in which a ruling has been made on one aspect of the AER's determination to correct an error, while ignoring that such an error must have countervailing impacts on a related matter. (This has particularly applied to the way in which the weighted cost of capital is calculated.) The National Electricity Law allows the regulator the capacity to bring such broader considerations to the notice of the Australian Competition Tribunal, but in practice, the regulator has not taken this approach (an issue discussed further in chapter 21).

In the case of the WACC, the Commission's recommendation (draft recommendation 5.2) about the need to address the interdependencies in its elements will help resolve one source of cherry-picking. The various progress reports by the limited merits review panel suggest that broader reforms to the processes are warranted and that, in particular, the review body should give primacy to the long-term interests of consumers (the National Electricity Objective) as its guiding principle in making its rulings.

Incentives faced by state owned enterprises

In Australia, electricity networks were originally fully state-owned. While some jurisdictions have chosen to privatise their electricity businesses, public ownership is still widespread in the sector.[31]

State-owned utilities obtain capital from state governments either largely through borrowing from the state treasury corporations or retaining earnings that might otherwise be paid to the relevant government in the form of dividends. Competitive neutrality arrangements should ensure that state-owned utilities enjoy no advantage with respect to their funding costs because of their government ownership. However, some parties claim that state-owned corporations (SOCs) receive debt and equity finance at below true market rates (and therefore a lower than market rate WACC).[32]

However, the Rules specify that the regulatory WACC should not take into account specific details of the firm in question, with the implication that the regulatory WACC should be the same for public and private firms. This has led to an ongoing debate about whether state-owned networks overinvest so that they can profit from the difference between their financing costs and the regulated rate of return. In turn, this has raised the question of whether the regulatory WACC should be lowered for state-owned businesses to remove any such incentive.[33]

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31 NSPs are publicly owned in New South Wales, Queensland and Tasmania and privately owned in Victoria and South Australia. ActewAGL in the ACT is partially privatised.

32 State governments' actions suggest that they are sometimes willing suppliers of 'low cost' equity and debt financing. This may occur because the opportunity cost of their funds is effectively the cost of the relevant state government debt, which is significantly lower than that of similar private sector firms and that allowed by regulators.

33 Those involved in this debate include: Garnaut (2011b, p. 42), the AEMC (2012a, p. 80), Major Energy Users (sub 11, p. 41), Grid Australia, (sub 22, p.30), the Energy Networks Association (sub 17, p. 207) and Ergon Enrgy (sub 8, p. 16).

Risk should be priced by project rather than by institution

In principle, the return on an investment should generally reflect the risk of the project, and not the underlying creditworthiness of the entity that funds it (a point also made by Grid Australia, sub. 22, p. 8). One way to illustrate this principle is that if a highly credit-worthy body, such as a state government, issues bonds and relends the money to a more risky body, it marginally decreases its own credit rating (because it is exposed to the higher riskiness of the borrower). Accordingly, the project risk cannot be removed just because a creditworthy lender provides the finance. As a result, the WACC should not be lower in these circumstances.

However, it is important that state governments:

- behave as an arm's length equity investor would, including demanding a return on equity that reflects the risk involved with the investment
- lend to state-owned network businesses (through their treasury corporations) at a rate that includes a properly calculated competitive neutrality fee. This is an adjustment that increases the borrowing cost to a level that the business would face were it to borrow in the private debt market.

If either of these conditions are not met, the state-owned business's capital costs will be effectively subsidised, in turn encouraging it to over-invest.

Difficulties surrounding estimating the return on equity (as discussed above), prevent a direct comparison of these costs, however, it is possible to compare the debt financing costs of publicly and privately owned NSPs. Table 5.1 (above) shows that the average cost of debt in state-owned electricity businesses is 6.86 per cent compared to 7.59 per cent in privately owned businesses. Prima facie, there appears to be a difference between the borrowing costs of state owned and privately owned businesses, even after the application of a competitive neutrality fee.

However, there is a large degree of variation between different businesses, both public and private, that reflects the individual credit rating of businesses, the timing of their capital programs and balance sheet management strategy (including dividend policy and debt and equity raising strategies) in inherently volatile capital markets. As a result, it is difficult to determine whether competitive neutrality principles are being applied in such a way that publicly owned businesses are facing borrowing costs equal to those faced by an equivalent private sector firm.

Even if competitive neutrality principles were not being applied in a way that gives full effect to the principle underlying them, and state-owned enterprises were receiving capital at a cheaper rate than an equivalent private business, the regulatory

WACC should not be adjusted to take this into account. If nothing else, it would be pragmatically difficult in any ex ante determination by the AER to estimate what an alternative WACC should be for any given SOC (noting the variability of margins shown in table 5.1). Instead, it is preferable to focus on ensuring that the competitive neutrality fee achieves its aim (and to the extent it does not, reveal to state and territory citizens the likely magnitudes of any subsidies to SOCs through low cost finance). Privatisation of state-owned networks, discussed in chapter 7, would resolve the issue without such complications.

Availability of debt and equity financing

The issue of cheap access to financing for state-owned network businesses is amplified by the fact that state treasury corporations appear to have been more likely to provide access to finance than if that finance were being provided to a privately owned NSP, a point made by the Major Energy Users:

> The clear indication is that the privately owned firms have the access to capital constrained more so than government owned firms which generally access needed capital in the form of debt from the government treasury corporations. That government owned energy firms have much more access to debt than privately owned firms have provides the government owned firms an incentive to invest more. (sub. 11, p. 18)

Such access was particularly important during the financial crisis. During this time, state treasury corporations appeared to be willing to continue to fund large capital expenditures by their NSPs while most privately owned corporations appeared to find raising either equity or debt both expensive and problematic.

To avoid concessionary financing of state-owned enterprises, such enterprises should be subject to financial market disciplines (that is, they should access finance on the same terms and with the same disciplines applied as the private sector).

Tax neutrality

The goal of shareholders in a private firm is to maximise the long term, post-tax returns of their business. However, under current competitive neutrality arrangements, a SOC pays an income tax equivalent to the state government (not the Australian Government). To the degree that a government shareholder can increase the capital spending of an NSP, which is then rolled into the SOC's regulatory asset base, it can trade-off any decrease in the post-tax rate of return and its greater receipt of income tax. A state government might conceivably influence a SOC in several ways. It could:

- be less aggressive in demanding only investment with adequate returns, and depending on the economic cycle, might be a more permissive financier than their private sector equivalents
- influence other aspects of the network business — for instance, by increasing the reliability standards beyond the level that corresponds with customers' willingness to pay for increased reliability— which can inflate the business's capital requirements and its regulated asset base.

In saying this, the Commission is not arguing that state governments explicitly or strategically set out to exploit their effective capacity to earn pre-tax returns on such investments. However, shareholders' usually strong incentives to constrain spending are likely to be muted.

It is hard to verify the extent to which this issue affects state government behaviour, but the incentives exist, as do perceptions by other stakeholders that governments react to these incentives (box 5.5).

As discussed above, it would not be appropriate to amend the WACC. Nevertheless, there are several policy responses that would reduce or remove the incentive problems:

In the absence of privatisation (which is the first best option), there are strong grounds to improve the effectiveness of competitive neutrality principles by removing the capacity of state governments to influence the capital expenditure decisions of the state-owned businesses. This would involve refining the governance arrangements of state-owned corporations (chapter 7). While not the main purpose of reform, the introduction of a NEM-wide reliability framework for transmission businesses and the creation of a single incentive regime for appropriate reliability in distribution networks, would remove one avenue for governments to influence capital expenditure (chapters 15 and 16). In theory, and in line with Garnaut's diagnosis of the source of the problem, it would be possible to amend the Commonwealth Grants Commission's GST allocation principles for the company tax receipts of state-owned corporations. The Commission has not considered this as an option, because among other factors, it would involve all state-owned corporations in all states and territories. The practicability, impacts and desirability of such a broad-ranging change are not clear.

However, of all the options, privatisation — as recommended in chapter 7 — would automatically resolve any problems, while bringing a range of other benefits.

Box 5.5 **Perceptions of governments influencing network decisions**

Major Energy Users:

> What does matter is that the government owner is incentivised to drive the government owned firm to chase increased profits as the government receives both the higher dividend and the higher corporate tax receipts which occurs when the government owned firm profit is unnecessarily high. As the government provides lower cost debt through the T-corps, and does not significantly limit the access to the debt, then the investment decisions of the government owned network are influenced by their shareholders. State governments set the reliability standards with little reference to the cost of these standards and thereby essentially influence the capital needs of the network firm. (sub. 11, p. 32)

The Garnaut Climate Change Review:

> Further, where the State Government is the owner, it retains the tax allowance for which provision is made in the weighted average cost of capital. Unlike taxation, royalties and many other sources of revenue, the profits of state-owned businesses are exempted from the equalisation rules under which the Commonwealth Grants Commission allocates GST revenues amongst the states. So there are cascading mechanisms through which the shareholders of state-owned businesses—like most electricity distribution businesses outside Victoria—do well out of over-investment. (Garnaut 2011, p. 42)

Bruce Mountain:

> The combinations of profit, the income tax on the profit and the debt guarantee/competitive neutrality fees have provided government owners of network service providers with extra-ordinary profits. In 2010 for example, the NSW Government received $596m in income tax equivalents and competitive neutrality fees from its distribution and transmission service providers and retailers. By comparison, dividends of $575m were paid in that year from these utilities ... This can be expected to have increased the sympathy that government owned NSPs have had towards higher capital expenditure. This is because higher capital expenditure has lead to a larger regulated asset base which in turn has delivered higher returns to state governments since the profit, income tax on profits and debt guarantee / competitive neutrality fees on the debt provided to fund the assets has risen as the asset base has expanded. (2012b, p. 18)

Revenue determinations are a repeated game

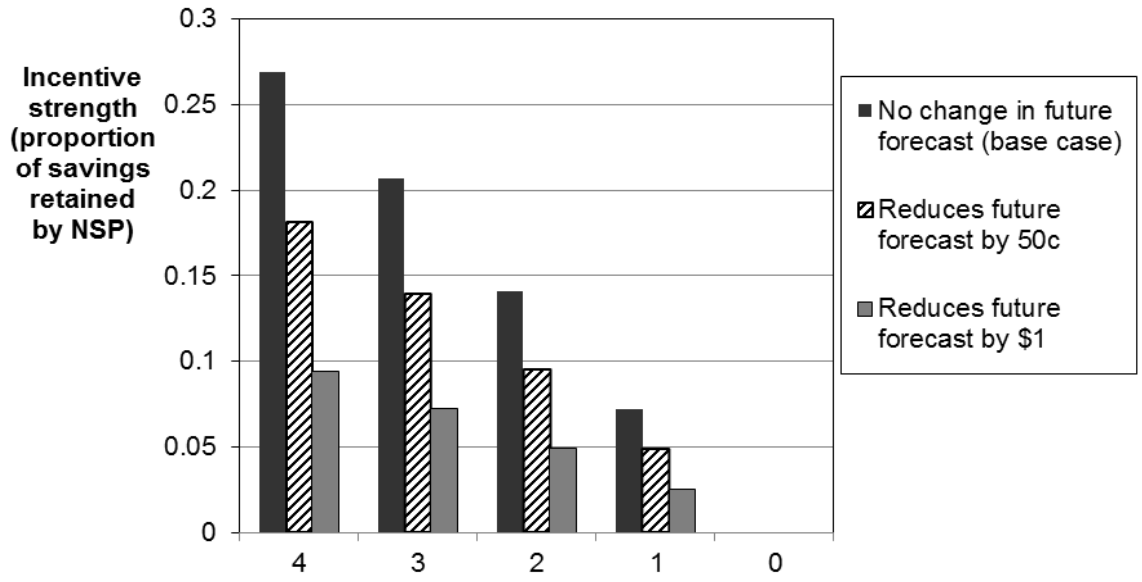
In theory, a business reveals its true costs after the completion of any given revenue determination, which the regulator can utilise in subsequent determinations.[34] (Indeed, this is a form of benchmarking.) However, to the extent that the AER uses such revealed cost information in its new determinations, it can alter the incentives faced by NSPs to lower their expenditure. For instance, a business may be concerned that if it outperforms (underspends) its capex forecast, the AER will

[34] Indeed, the regulator must have regard to past spending patterns — clauses 6.5.6(e)(5) and 6.5.7(e)(5) of the Rules.

simply use a stricter expenditure test in the next determination. This would lower the incentives for cost minimisation.[35]

To provide an idea of the potential impact of repeated determinations on current performance, figure 5.4 shows the incentives that would apply to capital expenditure using various assumptions of how future capex forecasts will be affected by a reduction in current expenditure. The base case assumes that the regulator ignores past expenditure, while the third case assumes that all reductions in capital expenditure result in an equal reduction in future forecasts. The second case assumes that this information is only partially incorporated. The value on the vertical axis represents the increase in the net value of the business from reducing capex spending by $1. Thus if the regulator ignores past information in the determination process, the strength of the incentive regime is much stronger than if cost reductions are incorporated in the next determination process.

Figure 5.4 **Using past performance in determinations affects present incentives**



a Commission calculations. Assumes a reduction in spending in the current period will result in a reduction in the capex allowance in the corresponding year of the next regulatory cycle. If it were instead assumed that reductions in spending impact across all years of the next regulatory period incentives in later years become negative. Assumes a 9 per cent WACC and a 50-year asset life.

In practice, it is unclear to what extent the AER incorporates information from past expenditures in future determinations. As stated by Biggar (2004):

35 This problem is effectively a re-statement of the regulatory dilemmas posed by high-powered versus low-powered incentive regimes (discussed in section 5.1). The more the regulator acts on past determinations, the lower the power of the incentive regime.

> …regulators are, understandably, reluctant to commit themselves to a single, mechanistic approach to setting future expenditure targets on the basis of past cost outturns. Yet, in the absence of such a mechanistic approach, it is impossible to be certain as to the precise incentive properties of a regulatory regime. (p. 3)

Nevertheless, some effect is likely.

However, these dynamic features of the incentive regime are one-sided.

- On the one hand, the AER considers past capex decisions in making ex ante determinations for future regulatory periods, thus weakening cost minimising incentives.
- On the other hand, given the forward-looking nature of WACC calculations, the AER does not do this for the WACC.

Accordingly, a regulatory WACC higher than the actual WACC for the business in one regulatory period is not followed by an adjustment in the next period, so that gaps between regulatory and actual WACCs can persist.

This will result in considerably weaker incentives to reduce capex than if the regulatory process was a once off game, and make the accuracy of the WACC a more important determinant of the overall strength of the incentive regime.

Treatment of overspending

Under the current regulatory arrangements, all capital spending — regardless of its efficiency — is rolled into the Regulatory Asset Base (RAB) at the end of the five-year regulatory period.

Addressing some of the problems which may lead to an excessive WACC, introducing an efficiency benefits sharing scheme for capex, and privatisation (chapter 7) may largely resolve inefficient overspends. Nevertheless, ex post reviews can provide an additional deterrent to inefficient spending. (And absent some of the above reforms, their benefits are likely to be considerably greater.) In its initial response to the AER's Rule change proposal, the AEMC (2012a) has recommended that the AER should have a capacity for ex post prudency reviews.

The essential feature of ex post reviews is that the regulator only allows capital expenditure that it deems to be prudent and efficient (given the information available to the network business at the time of its investment decisions) to be rolled into the RAB. The approach is widely used overseas and was a feature of the NEM prior to 2006 (AER 2011a). Given the difficulties of re-visiting all past expenditure decisions, such an ex post review could only realistically consider investment

decisions in the previous regulatory cycle, and would not attempt to conduct an entire revaluation of the RAB.

However, ex post reviews entail some risks of mistakenly identifying an efficient investment as inefficient. (If material, these risks would need to be reflected in the WACC.) The AER itself acknowledged that:

> … ex post reviews may add to regulatory risk by creating potential for investment write downs. In addition, the evidentiary burden that the regulator must satisfy before it could disallow an investment is so high that ex post reviews may offer limited protection against inefficient expenditure. (2011a, p. 43)

As summarised by the AEMC, the industry view was (unsurprisingly) negative:

> NSPs are not in support of ex post prudency and efficiency reviews of capex. They consider that a well-designed ex post prudency and efficiency review does not provide any additional incentives compared to a well-designed ex ante regime. (2012a, p. 119)

While acknowledging the drawbacks of an ex post review system, the Commission sees value in having it as a safety mechanism if spending levels are not being well controlled by the incentive structure. For this reason, ex post review should only apply if spending has materially exceeded forecasts within a given period. NSPs that are aware that spending is going to exceed forecast levels should be able to pre-apply to the AER for overspending in a given period, and thereby avoid the risk associated with an ex post review mechanism. Businesses would still have to carry the cost of this extra expenditure until the end of the regulatory period, as they do currently.

The ex post review of overspending would have to consider the total spending over the past regulatory period. Otherwise the NSP would likely selectively point to parts of its capex spending which were efficient and use these as the explanation for the overspend, potentially hiding inefficient expenditure in the process. Part of the intention behind the recommendation below is to provide a very strong motivation for the NSP to avoid an ex post review, by seeking approval in advance from the AER to exceed its forecast capex. However should a NSP not seek advanced permission to overspend its capex it seems reasonable that it should have an ex post review of the entire spending in the period, with the proviso that the AER, were it to identify inefficient spending, could only reduce the total capex to the previously agreed forecast.

DRAFT RECOMMENDATION 5.4

Where, within a given regulatory period, a network business spends materially more capital than that allowed for in the Australian Energy Regulator's final ex ante regulatory determination, then its entire capital expenditure should be subject to an ex post prudency test:

- ***Only spending that is deemed efficient and prudent, given the information available to the network business at the time, should be included in the Regulatory Asset Base at the end of the period, subject to the condition that:***
  - ***the maximum disallowable expenditure is no more than the difference between the ex ante forecast and realised expenditure***
- ***If a network businesses is aware that it is going to exceed pre-approved spending levels, it should be able to apply for pre-approval to avoid the ex post assessment.***

The prudency test should not apply to cost pass throughs and contingent projects permitted under chapters 6 and 6A of the National Electricity Rules.

5.4 The AER's ability to determine expenditure forecasts

As discussed earlier, in determining expenditure forecasts, the AER can only alter the proposal of the NSP consistent with the Rules. In particular, for both transmission and distribution networks, the AER must accept a proposal if it 'reasonably' reflects the efficient costs of that business.[36] In the case of distribution businesses (but not transmission businesses), if the AER does alter the initial proposal, it must set the alternative value on the basis of clause 6.12.3(f) of the Rules. This states that a substitute must be:

- determined on the basis of the current regulatory proposal
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

However, it is uncertain how much these rules bind the AER's decision making, and in particular, whether the:

- AER must accept the highest possible expenditure estimate that could be considered reasonable

36 NER clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c), and 6A.6.7(c).

- need to adopt the NSP's methodology precludes the use of top-down benchmarking
- AER must overcome an inappropriate evidentiary burden before changing a expenditure proposal
- current structure encourages NSPs to provide unnecessarily technical and detailed proposals to make it more difficult for the AER to challenge them.

The AEMC (2012a) is currently considering whether the AER is constrained by the Rules in these ways — an area of vigorous debate among the various stakeholders (box 5.6). Certainly, the AER's position is emphatic:

> As most proposals are based on a large amount of engineering detail and a 'bottom up' calculation of the required expenditure, the AER must conduct a line by line analysis in order to reduce the forecast to fall back within the 'reasonable' range. This inappropriately limits the AER's ability to weigh up all available data and determine an impartial forecast. (2011a, p. 13)

It has also documented a number of examples of where it feels it has been constrained. (AER 2012c, appendix 2).

On the other hand, the peak body representing network businesses, the Energy Networks Association, argue that the current rules do not constrain the AER in the way that it claims:

> Our assessment of the available evidence from AER determinations over the last five years does not support the AER's contentions that the current Rules are deficient in terms of:
>
> - resulting in systemically inflated expenditure forecasts having been reflected in determinations (and therefore higher electricity prices);
> - placing an evidentiary burden on the AER, which has further contributed to a systemic upward (statistical) bias in the determination of expenditure forecasts; and
> - placing additional restrictions on the AER's assessment of expenditure in the case of DNSPs. (2011a, appendix C, p. 50)

Box 5.6 Differing views on whether AER is constrained in its use of benchmarking

The Australian Energy Market Commission:

> …the extent of the constraint imposed on the AER by clause 6.12.3(f) is unclear. This could be read as merely requiring the AER to treat the NSP's proposal as an input into its determination of a capex or opex allowance, or as preventing an AER substitute from moving away from an NSP's proposal beyond what is necessary to result in a reasonable allowance. (AEMC 2012a, p. 104)

Allan Fels:

> …it is abundantly clear that the Energy Rules set out in some detail the methodology that is to be employed by the AER and the various constituent decisions that are to be made along the way. In this context, the AER‘s decision cannot be viewed as an assessment of the overall reasonableness of the business‘ proposal, but rather a conglomeration of several decisions on various aspects of that proposal. There is no provision that gives the AER an overarching discretion to determine a final price outcome that it considers to be in the public interest. (2012, p.57)

Ergon Energy

> Ergon Energy considers that the AER must be required to start from the regulatory proposal and make minimal adjustments to ensure prudent and efficient expenditure. A line-by-line assessment of the NSP's proposal is not necessary, and in fact the AER have made adjustments to capex and opex without undertaking a line by line assessment. (sub. 8, p. 14)

Consumer Action Law Centre:

> … it is of limited importance whether the AER already has the powers or discretion to achieve the outcomes it is proposing. If the AER does not believe it has, it will not act as such, and hence the outcomes will not be achieved. (sub. 5, p. 4)

ETSA Utilities, CitiPower and Powercor Australia

> The Businesses … consider that the Chapter 6 Rules have not constrained the AER in effectively discharging its responsibilities as the economic regulator. (sub. 6, p. 3)

The Brattle Group:

> … it may be that neither ‘adjusted only to the extent necessary’ nor ‘based on the NSP proposal’ are helpful guides to the exercise of the regulator’s judgement, in particular, if this were interpreted to rule out ‘top-down’ adjustments. We do not believe that it would be beneficial for the regulator’s discretion to be constrained in that way. It may be that clarification of the policy intent in this regard would be beneficial. (2012b, p. 10)

Michael B Cunningham:

> There is an explicit requirement to consider the benchmark opex and capex that would be incurred by an efficient DSNP. The AER must form a view about whether total opex and total capex reasonably meet the criteria of efficiency, prudency and being based on realistic expectations. The AER can form its own view on the evidence it considers pertinent when making that decision. These observations are consistent with the view of the AEMC that there is no constraint on the use of benchmarking within the NER if used within the building block approach. (sub. 28, p. 13)

Since the debates by stakeholders in part rely on varying legal interpretations of complex regulations, it is useful to consider whether any evidence of what has happened in practice could shed light on the extent of any constraints. There are in fact some indications that any constraints on how the AER approaches its task may not be substantial.

- One lens is to consider the institutional arrangements overseas to gauge whether the Australian approach deviates from good practice. The Brattle Group (2012b), looking at good regulatory practice to setting allowances as part of incentive-based regulation, found no fundamental differences between the approaches of the AER and the practices of regulators in other jurisdictions (Regulatory schemes in Great Britain, New Zealand, New South Wales, Western Australia, Ontario and Rhode Island were reviewed.) While in some jurisdictions the rules require regulators to test whether NSPs' forecasts are 'acceptable in relation to 'reasonableness', in others regulators can adjust forecasts if a 'better' one can be identified. The Group concluded that:

  > …regulators should (and do) weigh all of the relevant evidence. If the NSP forecast is not well-supported by the evidence, the regulator will place less weight on the NSP's forecast and more weight on other information available to it from the regulator's own analysis and the advice of technical consultant. (2012b, p. 2)

- While the AER claims that it has been unable to alter the proposals of NSPs to the extent that it would like, the evidence shows that the AER generally does alter initial proposals, and often by considerable amounts (table 5.4).

Table 5.4 **Distribution capex through the determination process**

Network operator	*Network proposal*	*AER draft determination*	*Network revised proposal*	*AER final decision*	*Percentage reduction from original*
	$m	$m	$m	$m	(%)
CitiPower	1167	676	1005	830	28.8
Powercor	1879	1300	1826	1567	16.6
JEN	657	372	621	473	27.9
SP AusNet	1484	1066	1582	1481	0.2
United Energy	911	652	949	887	2.6
Country Energy	4041	3955	3989	3826	5.3
Energy Australia	7381	7158	7050	6638	10.1
Integral Energy	2953	2914	2735	2721	7.8
Energex	6466	5718	6286	5783	10.6
Ergon	6033	5013	6274	4989	17.3
ETSA	2249	1628	1793	1588	29.4
ActewAGL	287	278	298	275	4.0
Aurora	675	536	618	535	20.7

Sources: AER determination papers.

- Moreover, the AER's determinations in this area have generally not been contested before the Australian Competition Tribunal (in contrast to the AER's WACC decisions), suggesting that the businesses do not believe they have sufficient grounds under the Rules to appeal against even determinations that significantly undercut their original proposals. The non-WACC determinations that have gone to the Tribunal have generally resulted in relatively small changes.
- The AER has used benchmarking of major components of spending as a major component of its reviews of pending proposals (box 4.3 in chapter 4) — something that would appear to be untenable were the AER obliged to sort through the 'entrails' of each proposal.

Nevertheless, while this evidence suggests that the AER has been able to successfully contest business expenditure proposals and to use aggregate benchmarking to some degree, it does not eliminate the possibility that the AER might still be overly constrained by the Rules:

- Had the Rules not included clause 6.12.3(f), it may be that the AER would have recommended even greater reductions in line with its analysis or could have avoided overly forensic analysis of the business proposals. The counterfactual is not observable.
- The AER does appear to have undertaken detailed analysis of the business' proposals in determining its alternative propositions.

So what is to be done?

In considering these issues, it is worth stepping back from the Rules. From the Commission's perspective some principles, however embodied in regulations, appear to be reasonable. In particular, the determination process should:

- in the first instance, be aimed at effectively achieving the National Electricity Objective
- be based on an economic, rather than a legalistic, mindset[37]
- take into account the incentives faced by the interested parties and the information asymmetries between them
- take account of all information that can cost-effectively be incorporated into the analysis, including bottom-up and top-down approaches (and

[37] A point made by the Energy Users Association of Australia (sub 24, p. 11).

benchmarking), while recognising the relative strengths and weaknesses of such approaches

- recognise that, over the longer term, undercompensation of network businesses resulting from regulatory errors is likely to have greater costs for customers and the wider community than 'equivalent' overcompensation (chapter 4).

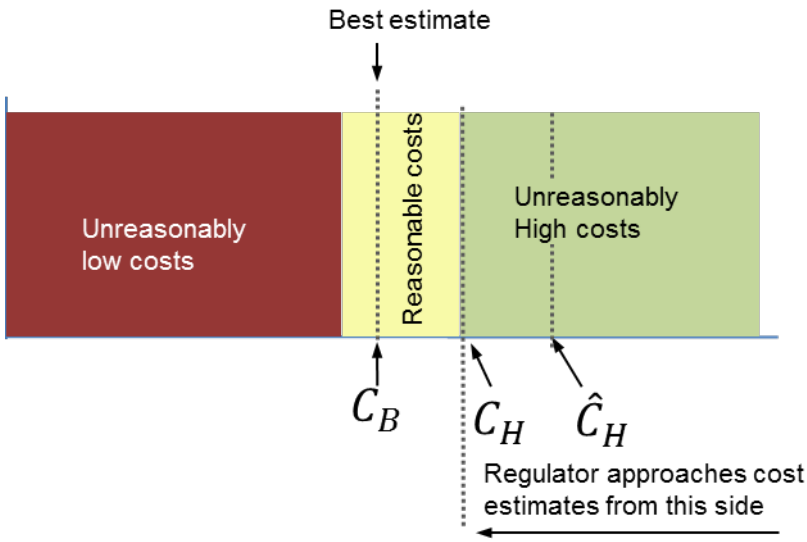
Given these principles, an improved propose-respond model could work as follows:

- The business would put forward its proposal, with enough information for the AER to commence its assessment.
- The AER and the business would interact while the AER considered the proposal. There might be many points where the AER required clarification or further information, and instances where the AER might seek feedback from the business (for example, 'Given the forecast demand, why couldn't this substation be deferred by 2 years?'). This process — and engagement — would reduce information asymmetries, help develop expertise among AER staff and allow the AER to test its views about alternative cost forecasts (if it has any).
- If, as a result of this process, the AER thought that the proposal was 'reasonable' it would accept it. In determining 'reasonableness' it would use the approach shown in figure 5.5. The AER would not seek to set the revenue allowance at the exact level that it perceived was necessary to provide the services required over the regulatory period (C_B). Rather it would start from the business proposal and reduce it just enough to meet a reasonableness criterion (which would be C_H in the figure).[38] That would create an expected rent for the business, but given uncertainty over cost forecasts would also insure the community against the risks of under-investment or poor management of assets.
- The expectation should be that the gap between C_H and C_B should not be too large, especially as the regulatory determination process is not a one-shot game. If the distribution network's performance appeared to be degrading (reasonably easily established in the case of distribution networks), and the business appeared to be otherwise efficient, then the next regulatory period would take account of this. Benchmarking could be used to narrow the range between C_H and C_B.

[38] This is consistent with the tenor of clause 6.12.3(f)(2), except that it is specific to the issue of reasonableness.

- The AER could use any method that it regarded as appropriate — including aggregate and partial benchmarking, engineering models, and highly disaggregated information in forming its views about what C_H should be. It would not be restricted to the original business proposal (as may be implied by clause 6.12.3(f)(1)). Accordingly, regardless of whether, in fact, the current Rules require it or not (a matter of legal interpretation), the Rules should explicitly indicate that the AER is only required to test the reasonableness of the overall expenditure proposal, rather than on the merits of all of its parts (an issue discussed further in chapter 8). This would increase the potential for the sensible use of benchmarking. However, given the difficulties associated with benchmarking identified in chapter 4, chapter 8 and by the AER itself, benchmarking would not play a determinative role.
- The AER's final determination would be subject to merit review if its holistic assessment was seen as failing the test graphically depicted in figure 5.5.
- The process should, where possible, be the same whether it is considering transmission or distribution networks — which raises the question about the extent to which chapters 6 and 6A could be harmonised.

Figure 5.5 **What is a reasonable cost?**



The Commission's suggested approach is close to that of the AEMC in its interim response to the AER's Rule change request.

It is possible that Rule changes that are intended to give effect to the above arrangements will not be sufficient to deliver outcomes that are closely aligned with the principles outlined above. The AER may find that instead of being permitted to set C_H, continued flaws in the way the revised Rules work in practice means that it

ends up being obliged to set $\hat{C}_H$. For this reason, if in the future, the AER feels unduly constrained in the way that it can challenge a proposal, it should publish its preferred estimate alongside the official estimate used for revenue purposes. This should lead to any issues being brought into the public domain and resolved in a timelier manner. It would also be information relevant to any merits review of the AER's determination.

DRAFT RECOMMENDATION 5.5

The National Electricity Rules should be clarified to indicate that the Australian Energy Regulator is only required to test the reasonableness of the overall expenditure proposal. The Regulator should only be obliged to consider the reasonableness of a specific expenditure item if it could materially affect the judgment of the reasonableness of the total expenditure forecast.

DRAFT RECOMMENDATION 5.6

In cases where the Australian Energy Regulator considers that the National Electricity Rules constrain its capacity to make appropriate revenue determinations, it should publish its preferred estimate along with the final determination, explaining the differences. In any subsequent merits review of its determination, the Australian Energy Regulator should ensure that the reasons behind its preferred estimate are clearly communicated to the merits review body.

The Commission seeks feedback on whether Chapters 6 and 6A of the Rules should be harmonised to support a common and coherent treatment of transmission and distribution networks (with differences confined to those areas where the different characteristics of transmission and distribution networks made these absolutely essential). Would this reduce the complexity currently caused by having two sets of Rules, lower costs for the Australian Energy Regulator, the Australian Energy Market Operator, the merits review body, and for consumers engaged in the regulatory process, and thus be more consistent with the National Electricity Objective? Would the benefits exceed the costs from any such transition?

6 Empirical evidence of network efficiency levels

Key points

- The scale of network capacity expansion has varied by a wide margin between networks. While much of the recent increase in network capacity appears to be related to peak demand, it is not clear that increased investment was the most efficient response.
- Expanding capacity has been more costly in some states than others, in that large expansions in the Regulated Asset Base (RAB) were required for a given increase in network capacity. This is partly attributed to differences in replacement capex, which is an area of expenditure that should be investigated further.
- Much of the recent increase in network revenues reflects the coincidence of increases in the Weighted Average Cost of Capital (WACC) and increasing capital expenditure. This particularly applies to New South Wales.
- Some firms may have benefited from being able to exceed regulatory allowances for capital expenditure in the previous regulatory period. Not only has this expenditure been rolled into the subsequent RAB, but it has also influenced decisions about what is reasonable expenditure. It is possible that some of this overspend could have reasonably been reduced or deferred.
- The performance of distribution networks often appear to differ between states. This may reflect a number of issues, including reliability standards and ownership arrangements.
- There are significant differences in network behaviour and apparent efficiency between state and privately owned networks.

While the Commission has not undertaken an elaborate benchmarking analysis, it is useful to consider whether there is a prima facie case that significant inefficiency exists. That would shore up the basis for further benchmarking — and for it to play a greater role in future regulation. However, in light of the many qualifications emphasised in chapter 4, the results are indicative, and certainly would not constitute a reliable basis for any downward adjustment in revenue allowances in imminent regulatory determinations. In particular, this chapter has concentrated on partial indicators. None of the partial indicators would themselves provide definitive evidence of inefficiency, but collectively they may provide more robust evidence.

This chapter first outlines the prevailing evidence on network inefficiency, including some of the more contentious findings (section 6.1). Section 6.2 considers further evidence on various contested issues, such as the relative role of changes in the regulated WACC, (largely outside the control of individual businesses, save for the appeals mechanism), and increases in expenditure (which is largely controlled by the business). On the decisions made by networks, this chapter discusses various arguments including:

- how decisions on physical augmentation have related to peak demand (section 6.3)
- whether measures of the regulated asset base can be useful as indicators of efficiency, and how these relate to both growth capex and replacement capex (section 6.4)
- the significance of overspending, given the incentives outlined in chapter 5 (section 6.5).
- whether the state-owned networks operate differently from the privately-owned businesses (section 6.6).

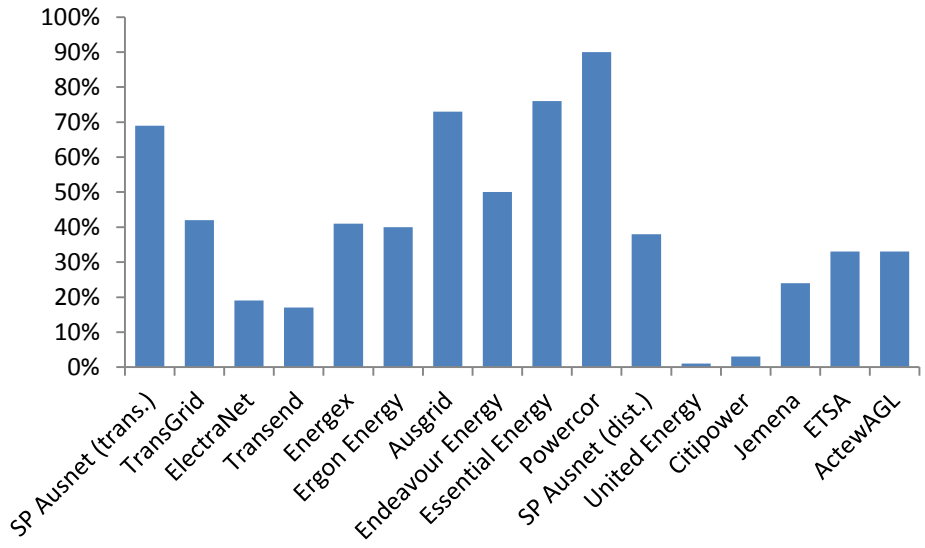
6.1 Existing evidence and arguments

As discussed in chapter 2, the electricity supply chain as a whole has recorded negative productivity growth in recent years. Topp and Kulys (2012) note the negative growth phase in multi-factor productivity coincided with a trend of rising peak demand, as well as declining network capacity utilisation. As such, the increase in network capacity is likely to have been a factor in the recent fall in productivity.

The expansion in network-related costs is confirmed by the AER (2011a), which notes that network revenue allowances have risen significantly in the current determination period (figure 6.1). This expansion is expected to have a significant effect on electricity prices — AEMC (2011a) estimated that distribution charges will account for 42 per cent of the expected electricity price increases between 2011 and 2014, with transmission accounting for 7 per cent.

Figure 6.1 **Approved network revenues have risen**

Percentage rise in approved revenues from the previous to current regulatory period



Data source: AER (2011a).

Some studies suggest there is widespread inefficiency

The AER has questioned the efficiency of recent expenditure increases in its rule change proposal to the AEMC.

> Recent increases in network charges have been driven in part by the need for increased investment to replace ageing assets and to meet increased peak demand, growing customer connections and higher reliability standards. Higher forecasts to cover expected increases in labour and materials costs have also contributed to increases in network prices. However, these drivers do not fully account for the level of observed increases. (AER 2011a, p. 6)
>
> There are legitimate reasons for some increases in capex from previous levels. However the sharp and significant step change in expenditure forecasts draws into question whether the current framework is meeting the [National Electricity Objective] in 'promoting efficient investment' or whether it is stimulating investment above efficient levels. (AER 2011a, p. 8)

The AER cites as evidence the large and rapid increases in both forecast and actual expenditure. For instance, capex forecasts in the AER's first round of distribution determinations were 64 per cent higher on average than the actual expenditure incurred in the previous period, while opex forecasts were 34 per cent higher.

Several other commentators have also characterised recent network expenditure as inefficient, with network over-expenditure contributing significantly to price outcomes. For instance, Garnaut states:

> There have been large recent electricity price rises that are not related to a carbon price, and without changes in the regulatory arrangements, this would continue. The increases are mainly because of large investments in the networks of poles and wires that distribute electricity, and the high rates of return on those investments that are recouped without risk from consumers. (2011a, pp. 149–50)

Mountain and Littlechild (2010) and Mountain (2011) provided more extensive evidence on the degree of potential inefficiency by comparing selected Australian States and the United Kingdom. They found that:

- revenue and expenditure allowances (on a per customer basis) were substantially higher in New South Wales and Queensland than in Victoria and South Australia, and increasingly so
- state-owned networks (New South Wales and Queensland) were more costly in terms of their regulated asset base, revenue and expenditure per customer compared to private networks (Victoria and South Australia). This remained the case when they were split into urban and country networks
- in comparisons with New South Wales and Victoria, the United Kingdom appeared to have much lower allowed revenues, expenditure and RAB per customer.

The estimated efficiency gaps were also particularly large (box 6.1). Mountain summarised the outcomes of the quantitative work:

> Efficiency benchmarking using regressions shows that government owned distributors are, on average, half as efficient as the privately owned distributors. In other words, their total expenditure would need to halve to reach the level of efficiency of the privately owned distributors. … Furthermore, comparison with the performance of electricity distributors in Britain suggests that Australian distributors are lagging behind: distributor revenues per connection are twice as high in Victoria, three times in South Australia and four times as high in Queensland and New South Wales. (Mountain 2011, p. vi)

It is doubtful, given their large magnitude, that these gaps genuinely reflect differences in the underlying productive efficiency of the businesses. Other factors, such as differences in the cost of capital, exchange rates, and the absence of some important environmental factors may also contribute — criticisms that are addressed in the next section. Nevertheless, even if the apparent inefficiency of the New South Wales businesses (as measured against a Victorian benchmark) were to be reduced significantly — by 75 per cent, for example — it would still amount to a high level of inefficiency.

Box 6.1 **Contentious findings**

Mountain and Littlechild (2010) compared partial productivity indicators of New South Wales, Victoria and Great Britain. The variables used included allowed revenue per customer; allowed capex and opex per customer; RAB per customer, and the WACC. The latest available exchange rate was used, which was 56 pence per dollar. They found that allowed annual revenue per customer in Victoria was about 61 per cent of the level in New South Wales in 2010. They also found that network revenue in New South Wales was around twice that of Great Britain in the year 2000, and would be nearly four times as much in 2014.

If New South Wales had assumed the same level of opex per customer as Great Britain in the third price control, the allowed revenue per customer in 2014 would have been 24 per cent lower. If it had used the same WACC as applied to Great Britain, the allowed revenue per customer for New South Wales would have been 21 per cent lower. The combination of capex and RAB accounts for the remaining 28 per cent difference.

In a report for the Energy Users Association of Australia (EUAA), Mountain (2011) found that state owned distributors had 60 per cent more capex allowed per customer than privately owned distributors in 2002, and this was expected to rise to almost 300 per cent in 2014. The allowed revenues per customer in New South Wales and Queensland are expected to be of a comparable level in 2014, at roughly 1.5 times the level in South Australia, twice the level in Victoria and four times the level in Great Britain

In a separate report for the EUAA, Mountain (2012a) compared household electricity prices between Australia and various countries. In 2011-12, average household electricity prices in Australia were around $0.25 per kWh — this was 12 per cent higher than average prices in Japan, 33 per cent higher than the European Union average, 122 per cent higher than the United States average; and 194 per cent higher than Canadian average. However, Mountain also shows that the results are somewhat sensitive to the choice of exchange rates. Using 2007 exchange rates, Australia was on par with the EU average, while still around 30 per cent higher than Japan. Under Purchasing Power Parity, Australia's average price was below those of Japan and the European Union.

Sources: Mountain and Littlechild (2010); Mountain (2011, 2012a).

Other benchmarking studies of Australian network businesses, many of which were undertaken or commissioned by regulators, suggest that performance has varied significantly between firms at various points in time (box 6.2). However, most did not report efficiency gaps as wide as Mountain (2011).

Box 6.2 **Efficiency gaps identified by recent studies**

Several studies examined partial indicators of efficiency:

- Wilson Cook (2009) made several partial productivity comparisons between Western Power and the distribution network operators in several other states. Comparisons were made of opex ratios, although the comparisons did not offer a consistent conclusion on the size of efficiency gaps between networks. Victoria had a similar level of opex per customer as South Australia, which was around one third less than Western Power, New South Wales/ ACT, and Queensland. However, when comparing opex per circuit km, Victoria was close to on par with Queensland, and more than one third higher than South Australia.
- BRW (2004) undertook several comparisons between Energex and various other distributors for the Queensland Competition Authority. Indicators included reliability measures, and various expenditure ratios. Compared to the three most comparable firms, Energex had the lowest opex per circuit km, opex per customer and opex per GWh (with Energy Australia being 85–99 per cent higher than Energex in these measures). This helped to explain why Energex's opex was to grow by around 63 per cent over the subsequent three years.
- Meyrick (2005) undertook comparisons between Western Power and all other Australian distribution networks who remained unidentified. Meyrick used a number of partial productivity measures, although mainly reported rankings. Opex productivity indexes ranged from around 0.6 to 1.8, while capex productivity ranged from around 0.6 to 1.5.

Comprehensive indicators of efficiency have also been used with Australian networks:

- ESC and PEG (2006) estimated Total Factor Productivity (TFP) trends in four Australian States. They estimated that TFP trends have grown at about 2.14 per cent per annum in Victoria, compared to about 1.8 per cent in Tasmania, 0.14 per cent in New South Wales and -0.03 per cent in South Australia.
- London Economics (1999) compared New South Wales to other distribution networks using Data Envelopment Analysis (DEA) and TFP methods. The comparisons were made to distribution networks in the United States, United Kingdom, Wales and New Zealand. Based on adjusted DEA scores, it was estimated that New South Wales distribution networks would need to reduce their input use by between 13–41 per cent to meet the efficiency frontier.
- Meyrick (2005) undertook multilateral TFP comparisons, where Western Power is ranked sixth out of thirteen, and is 6 per cent below the group average.
- IPART (2010) assessed the productivity of a range of NSW state owned corporations including electricity network operators. Among distributors, it estimated a TFP decrease between 2001-02 and 2008-09 of between 17 and 24 per cent. Using an alternative model specification, it measured decreases of between 7 and 19 per cent.

Sources: BRW (2004); ESC & PEG (2006); IPART (2010); London Economics (1999); Meyrick (2005); Wilson Cook (2009).

Has the case for inefficiency been made?

As Yarrow (2012) observed, opposing commentators in the industry often cite different forms of evidence, and so it is not surprising that some of the studies mentioned above have been strongly disputed.

Networks have acknowledged that both prices and expenditures have risen, although they have collectively argued that the increases are in response to peak demand, replacement of ageing infrastructure and changes to regulatory compliance. The ENA, for example, said:

> The ENA contends that … the increases are efficient because the regulatory framework under the Rules accurately reflects a range of relevant changes including:
>
> - increases in the prevailing cost of capital due to the global financial crisis;
> - increases in the need to replace assets due to an increasingly significant proportion of asset stock reaching the end of its economic life;
> - changes to network planning standards; and
> - continuing increases in peak demand that outstrip growth in energy usage due, for example, to the increased penetration of air conditioning. (sub. 17, p. 7)

In particular, network businesses have questioned the stark findings of Mountain's various studies. NERA, on behalf of the ENA (sub. 17, appendix B), examined the various Mountain studies, concluding that:

> Our assessment of the analysis undertaken in Mountain strongly suggests that it provides an insufficient basis for such conclusions. Failure to consider the many legitimate reasons for variances in costs and a reliance on inappropriate comparisons has resulted in Mountain drawing unsubstantiated conclusions about the relative efficiency of DNSPs. (p. i)

NERA's criticisms of Mountain's studies were far-reaching:

Mountain's Australian evidence

NERA pointed out several limitations in Mountain's 2011 study (and effectively Mountain and Littlechild's 2010 paper), including that it:

- used a model specification that ignored the fixed costs of networks (by setting a zero intercept in his regression model)
- failed to report any specification tests
- did not systematically consider the ratio of peak to average demand or the lumpy nature of investment
- did not control for all differences in the operating conditions between firms.

Of these points, the first two are correct, albeit it is not clear that much of a bias is associated with Mountain's assumption about the intercept.

The third point is true in terms of the regression analysis since Mountain did not include the load factor as a regressor. However Mountain (2011 pp. 35ff) did consider the role of peak demand when assessing the outcomes in Victoria (which was rated as the state with the most efficient businesses). Prima facie, peak demand does not appear to be a distinctive driver of the difference in investment levels between New South Wales and Victoria.

The fourth point is true, but inevitably so for any model based on a limited sample.[1] Perhaps one of the most important concerns is the fact that, ideally, benchmarking analysis should take account of businesses' need to replace assets close to the end of their lives. Instead, Mountain compared the (weighted average) remaining life of assets of distribution network businesses in Victoria and South Australia with businesses in New South Wales and Queensland (finding the latter longer). NERA's concern is that what matters is the quantum of assets getting close to the point of expiry, not the weighted average age. NERA provides data comparing the distribution of asset lives for Ausgrid and SP Ausnet, which suggests that Ausgrid would need a greater capex expansion rate given its asset vintage distribution. However, the expansion rate in New South Wales is not just moderately higher than Victoria. Mountain finds that the New South Wales distributors received four times more capex per customer to replace ageing assets than Victorian businesses. If nothing else, this is an issue warranting further investigation.

The UK–Australia comparisons

In the case of the international comparisons of Australia with the UK, NERA correctly pointed out that Mountain used market exchange rates, not purchasing power parity rates (for which there is more theoretical justification). It noted that peak demand was higher in Australia. Finally, it speculated that different accounting practices might also be present and that the asset replacement cycle might have been different between the two countries.

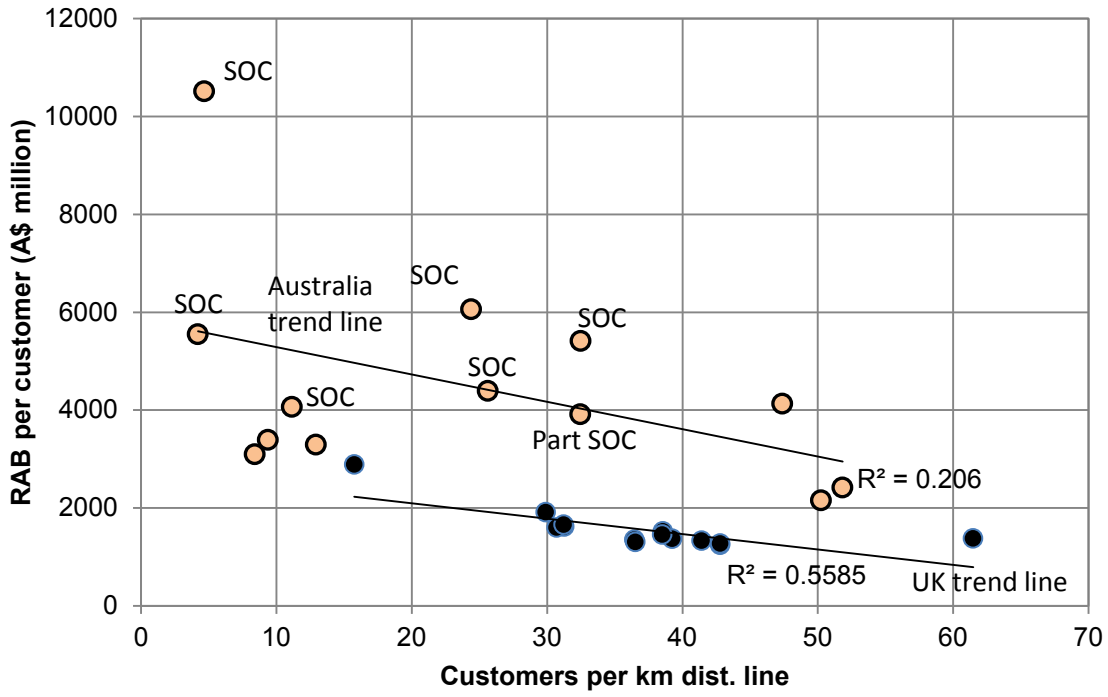
However, to assess some of these criticisms, the Commission adjusted for purchasing power parity rates (figure 6.2). It appears that the RAB per customer for

[1] It is also not necessarily a damning finding. Any regression model must have omitted variables. If important causal variables are left out of the model, this leads to 'omitted variable bias'. If, for example, there are several important variables omitted, then the inclusion of some (or one) of them may reduce the bias or simply change the magnitude or direction of the bias — the effect is not necessarily clear (Clarke 2005).

every Australian distribution business (after controlling for customers per kilometre of lines) is higher than that for distribution businesses in the UK. It is also apparent that the dispersion in apparent inefficiency scores (measured against the best practice performer) is much greater in Australia than in the UK. Many of the higher relative inefficiency scores relate to state-owned corporations, though there may be other variables correlated to ownership that lead to this pattern. While NERA is correct to point out the differences in peak demand, they do not mention other factors that may lead to countervailing cost pressures, such as a greater degree of undergrounding in the UK.

There are significant drawbacks in international comparisons (chapter 4) and, as such, Mountain's results and figure 6.2 are interesting but flawed. Nevertheless, they provide an indicator to be weighed up against others.

Figure 6.2 **Australian versus UK asset bases per customer**[a]



[a] Note the importance of taking care when interpreting RABs, as discussed in section 6.4 of this chapter. PPPs have been used to convert currencies. SOC denotes a state-owned corporation.

Data source: PC calculations.

Notwithstanding the various flaws in Mountain's research, the counter-evidence is not so strong as to invalidate the basic thrust of his conclusions. In its recent draft determination for the AER's Rule change proposal, the AEMC (2012a, p. 97) reached much the same conclusion:

> … no analysis has been provided which would challenge Mountain's conclusion that the average privately-owned DNSP [distribution network service provider] is more efficient than the average state-owned DNSP.

But more evidence is needed

Several commentators have highlighted the need for more detailed evidence of inefficiency (ENA, sub. 17, appendix A or B; Yarrow 2012). For example, Yarrow noted that:

> … much more specificity in the identification of causal links is required, even to [begin] to pin down the elements of the wider system of relationships that might usefully be considered to be candidates for reform.
>
> … In relation to capital costs for example, it can be asked: if there is a tendency for networks to over-forecast, why do a number of utilities then tend to over-spend relative to such inflated forecasts?
>
> … Is it that utilities simply take on too many projects, or that they over-engineer projects? Or is it that utilities undertake the wrong projects? Or then again, is it just that whatever they do, they do it at a higher cost than necessary? None of this is very clear. (p. 10)

The Commission has identified many data and model development problems (chapter 4 and 8), for which resolution would be the necessary precursor for more definitive benchmarking. However, there is some evidence — beyond that analysed by Mountain — that provides further information about the cost drivers behind recent network price increases.

6.2 The relative impacts of the WACC, capex and opex

The rise in network revenues have had several significant drivers. In a report prepared for the ENA (sub. 17, appendix A), NERA undertook an extensive analysis of these drivers between the current and previous regulatory periods.[2] NERA's calculations first involved considering what network charges would have been if both the WACC and expenditure allowances had remained constant from one regulatory period to the next. It then calculated the percentage difference

[2] For distribution companies, NERA analysed the regulatory period corresponding with the first AER distribution determination for that region, and with the determination immediately prior to AER regulation. Aurora Energy is not included in the analysis, as the AER had not completed its determination at the time. For transmission companies, NERA analysed the regulatory period in each region current in 2012, as well as the regulatory period immediately prior to that. CME (2012) also examined the impact of WACC changes on revenue allowances, but only those changes due to decisions by the Australian Competition Tribunal.

between this price and the actual network charge, noting the percentage contribution from changes in capex allowances, opex allowances and the WACC (table 6.1).

Table 6.1 **Breakdown of network charge increases from previous regulatory period to current regulatory period[a]**

Percentage contribution to overall price increases

Network operator	*Capex allowance*	*Opex allowance*	*WACC*	*Other[b]*	*Total*
	Per cent	Per cent	Per cent	Per cent	Per cent
Ausgrid	18.6	15.6	14.6	12.2	58.3
Endeavour	9.5	9.9	11.2	3.8	32.9
Essential	15.7	20.2	11.4	4.5	49.7
TransGrid	9.4	4.3	8.7	(2.8)	18.2
Ausgrid Transmission	29.9	16.0	4.9	3.7	46.8
Energex	8.8	2.7	18.9	14.2	42.6
Ergon	7.2	7.9	17.8	16.2	47.5
ETSA	10.6	10.0	10.4	7.8	36.4
ElectraNet	8.5	2.7	14.1	10.3	33.9
ActewAGL	4.6	18.2	(0.6)	0.7	22.7
Transend	9.1	10.6	7.5	5.9	32.5
CitiPower	1.2	1.2	4.9	(5.5)	1.4
Powercor	3.4	3.7	4.1	4.4	6.3
Jemena	1.6	(3.6)	6.6	6.8	11.0
SP Ausnet	6.8	9.2	6.3	2.3	19.2
United Energy	4.2	2.8	3.8	4.9	5.6
SP Ausnet Transmission	3.1	1.1	3.2	5.5	15.3

a For distribution companies, NERA analysed the regulatory period corresponding with the first AER distribution determination for that region, and with the determination immediately prior to AER regulation. Aurora Energy is not included in the analysis, as their first determination by the AER had yet to be completed. For transmission companies, NERA analysed the regulatory period in each region which was current in 2012, as well as the regulatory period immediately prior. **b** 'Other' factors contributing to network charge increases include capex and opex overspends. For networks subject to price cap regulation, 'other' factors may also be attributed to differences in forecast and actual demand. When decomposing the percentage change in a multiplicative measure, there are 'mix' effects that pick up the interactive movement of the variables. 'Other' factors also includes these 'mix' effects. Overall, the implication is that the role of the WACC, as well as *actual* capex and opex, are likely to be larger than identified above.

Source: ENA sub. 17, appendix A.

Network charges are generally higher in the current regulatory period compared to the previous period. The magnitude of increase has not been uniform, with relatively large increases for firms based in New South Wales, Queensland and South Australia.[3] The source of the cost pressures have also varied. For Ausgrid, changes in the capex allowance have been a major driver of network charges, while

3 NERA (ENA sub. 17, appendix A) excluded Tasmania from its analysis.

for Energex and Ergon, the main drivers included increases to the WACC and 'other' factors (including above-allowance expenditure).

In explaining the expenditure increases, NERA found that 'real cost escalators'[4] had a small negative effect on capex allowance since the last period, meaning that the unit costs associated with capex had fallen. Hence, with respect to capex, the main drivers were likely to be the increased scope and number of capex projects rather than their cost escalators. At the same time, real cost escalators had a significant effect resulting in increased opex allowances, contributing between 1.9 and 2.4 per cent to distribution opex allowances, and up to 3.5 per cent for transmission allowances (p. 48).

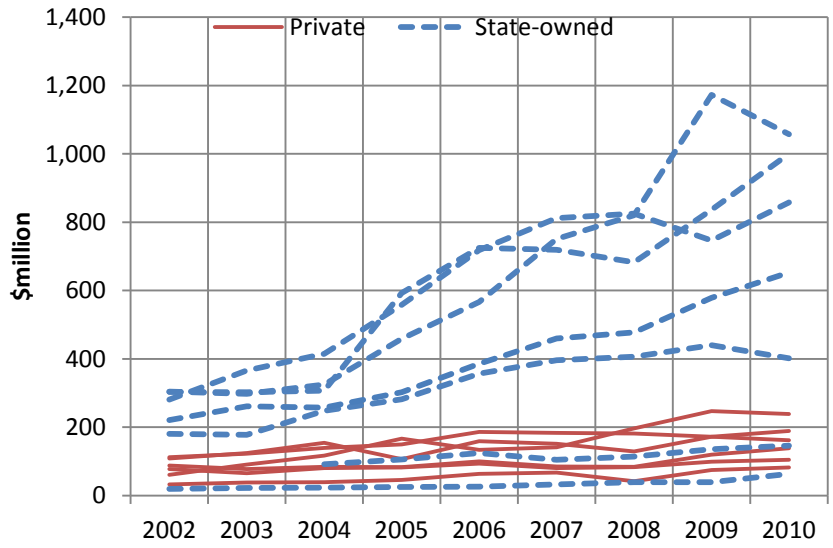
NERA's analysis implicitly used the previous regulatory period as a benchmark. This is a reasonable specification, given that the analysis focused on the impact of the new regulatory framework on costs. However, in considering the efficiency of networks more generally, other benchmarks could be used — for instance, the analysis could reasonably be extended to prior regulatory periods. The analysis also focuses on cost increases associated with expenditure allowances, rather than the actual expenditures (which may be more or less than the approved level).

An analysis of actual distribution capex in the periods *prior* to AER regulation shows that the scale of actual expenditure in the largest states of the National Electricity Market, (New South Wales and Queensland), has increased several times over (figure 6.3). As such, it is important to consider previous as well as current drivers of expenditure.

4 Real cost escalators are indices representing the change in prices faced by network businesses. These may include prices for materials, construction costs, and wages.

Figure 6.3 **The scale of recent capital expenditure for distribution networks**

Annual capital expenditure



a The first year of AER regulation of distribution networks was: 2009-10 for NSW and ACT; 2010-11 for Queensland; 2011 for Victoria; 2011 for South Australia; 2012-13 for Tasmania.

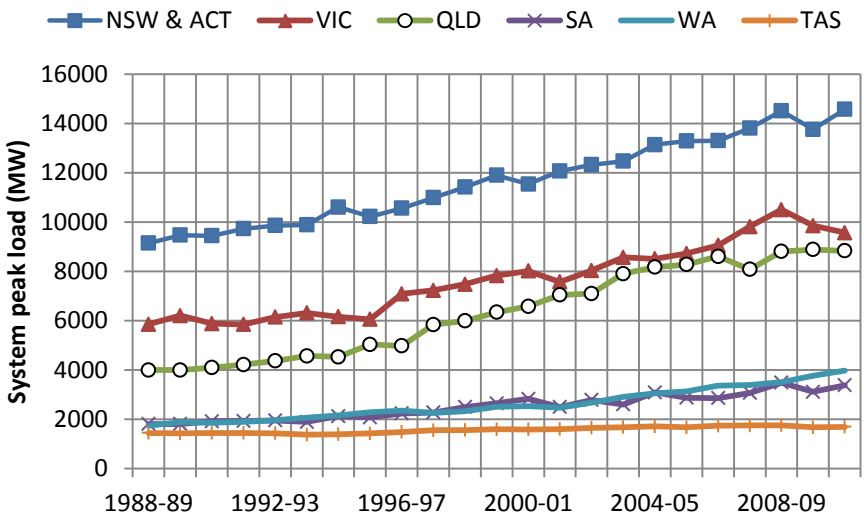
Data source: AER unpublished data.

6.3 Demand driven augmentation

Recent decades have seen the rise of peak demand (Topp and Kulys 2012). This has been evident in most jurisdictions, although Queensland has had a particularly rapid increase, with its peak load doubling since the early 1990s (figure 6.4). Growth in peak load levels has slowed in most states since 2008-09, and has been lower than forecast in New South Wales and Queensland (NSW Government 2010).[5]

5 Although data is unavailable on an individual network basis, it is likely that each distribution network experiences a different level of peak demand even where they exist within the same state.

Figure 6.4 **Rising peak demand**



Data source: ESAA reports various years.

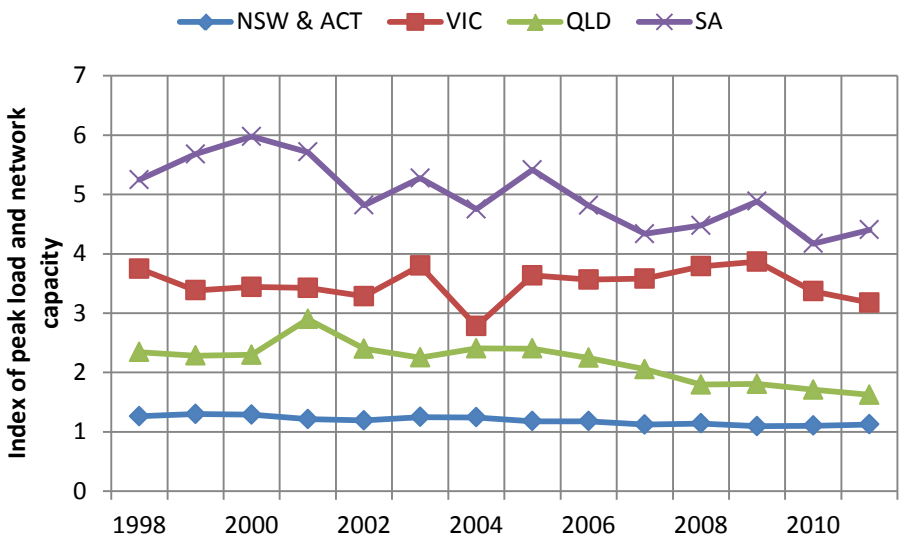
Unsurprisingly, the capital expenditure increases in New South Wales and Queensland were mainly on system assets — this includes network augmentation and replacement, and excludes non-system assets such as monitoring and IT systems. Since 2001, expenditure on system assets has accounted for more than two-thirds of New South Wales capex and over 84 per cent in Queensland. As Nuttall notes:

> To counter these external pressures, a very large augmentation program has been undertaken in Queensland. … In both Queensland and NSW, the majority of the [transmission] line developments have occurred since 2006 – noting that this is during the period when growth rates have been at their lowest and actual peak demand has been lower than forecast. (AEMO, sub. 42, p. 5)

The result can be seen in indicative comparisons of ratios of peak load and network capacity (figures 6.5 and 6.6).[6] After a spike in 2001, this ratio falls for Queensland as a result of ongoing network augmentation.

6 Network capacity is measured by the product of total installed transformer capacity (measured in MVA) and the aggregate length of network lines (in circuit km). It is a physical measure of network supply capacity — a similar measure is used by Topp and Kulys (2012). The ratio of network capacity to peak load is used as an indicative measure only, to illustrate the trends in network capacity relative to trends in peak load and to make relative comparisons between networks. It is not intended to be an accurate measure of asset utilisation levels.

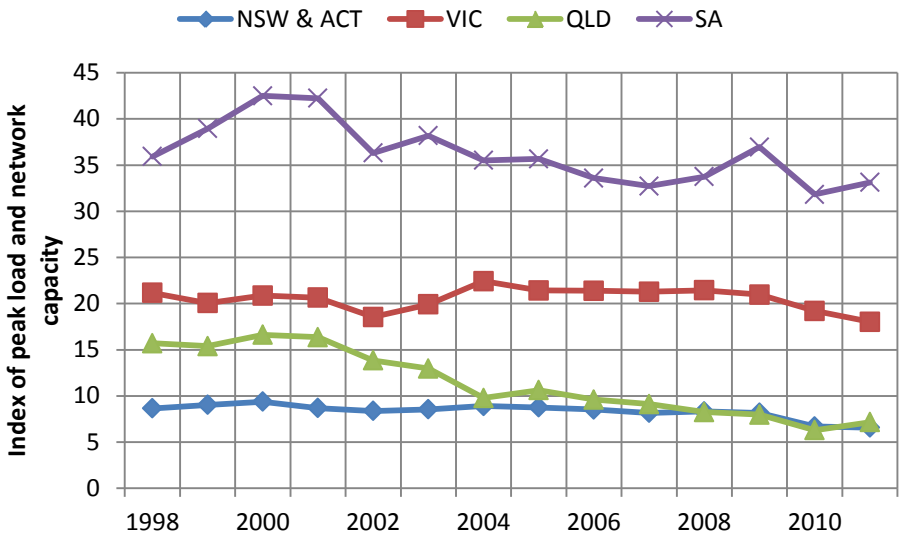
Figure 6.5 Index of distribution network capacity relative to peak load[a]



[a] Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA). The graph shows the ratio of peak load to network capacity. Peak load is a state-wide measure, and was not corrected for weather. The ratio is indicative only, and is intended to compare trends.

Data source: ESAA reports various years.

Figure 6.6 Index of transmission network capacity relative to peak load[a]



[a] Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA). The graph shows the ratio of peak load to network capacity. Peak load is a state-wide measure, was not corrected for weather. The ratio is indicative only, and is intended to compare trends.

Data source: ESAA reports various years.

Not all networks have taken the same approach. While peak demand has also risen in Victoria, its augmentation levels have been relatively lower than New South Wales and Queensland. As AEMO have described:

> Victoria, on the other hand, has seen relatively modest augmentation levels, making use of load shedding control schemes, line uprating opportunities, and additional capacity released through the real-time rating system adopted in Victoria. [Transmission level] transformer capacity over 2000 to 2011 increased by around 25 per cent, with line capacity only increasing by approximately 3 per cent. (sub. 42, p. 5)

The comparisons suggest that trends in network augmentation relative to peak demand have historically differed between states, and that these differences have not been created solely by the events in the last regulatory period. This high-level evidence also suggests that while Queensland had changed its approach during the last decade, the increases in peak demand of the last decade are unlikely to explain *all* of the physical differences between networks, particularly between Victoria and New South Wales.

The main form of augmentation in Queensland has been through the rapid increase in transformer capacity. Queensland has increased its transformer density in response to peak demand (AEMO, sub. 42). In the ten years from 2001, transformer capacity in Queensland grew by 130 per cent — more than it had grown in the preceding 23 years. Based on these high-level data, Queensland has not simply adjusted for recent increases in peak demand, but has also increased its transformer capacity relative to peak load.

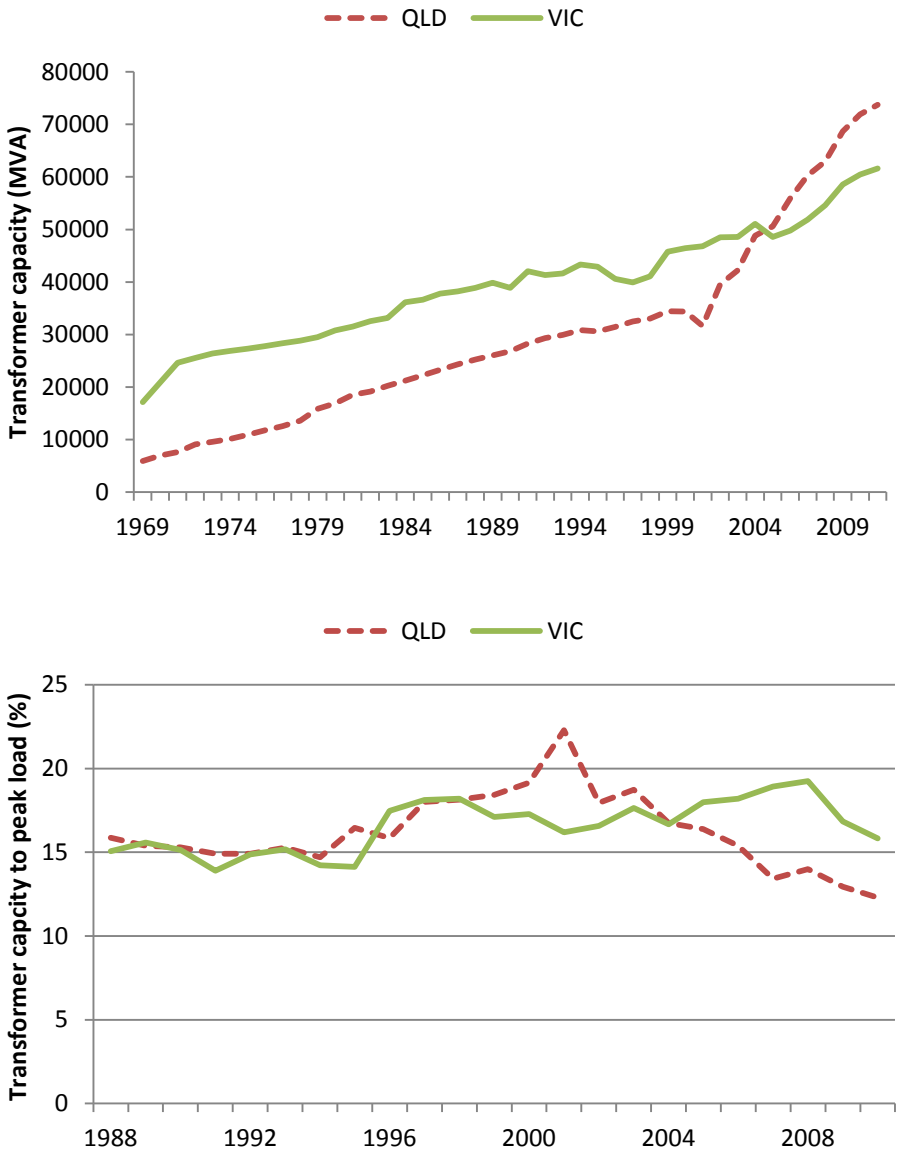
This change in trend appears to have begun after a spike in the peak transformer capacity utilisation in 2001(figure 6.7). For much of the 1990s, the ratio of peak demand to transformer capacity was similar between Queensland and Victoria. However, following a surge in the utilisation of transformer capacity, Queensland has maintained a strong expansion whereas Victoria has not.

Based on forecasts of electricity demand[7], peak demand is likely to continue to grow more strongly in Queensland than in other states (ESAA 2012, AEMO 2012). If the ratio between peak demand and transformer capacity were to be kept constant at current levels, Queensland would need to maintain a rate of expansion in transformer capacity similar to its current trend growth rate.

[7] Forecasts of peak electricity demand for each state up to 2021 have been made by AEMO (2012).

Figure 6.7 **Transformer capacity in Queensland and Victoria relative to peak load[a]**

Transmission and distribution level transformers



a Includes distribution and transmission level transformers. Utilisation rates are calculated using peak load for the year.

Data source: ESAA reports various years.

The need for more detailed information on asset utilisation

There are limitations to what can be decisively inferred from high-level comparisons of average network utilisation. As Grid Australia said:

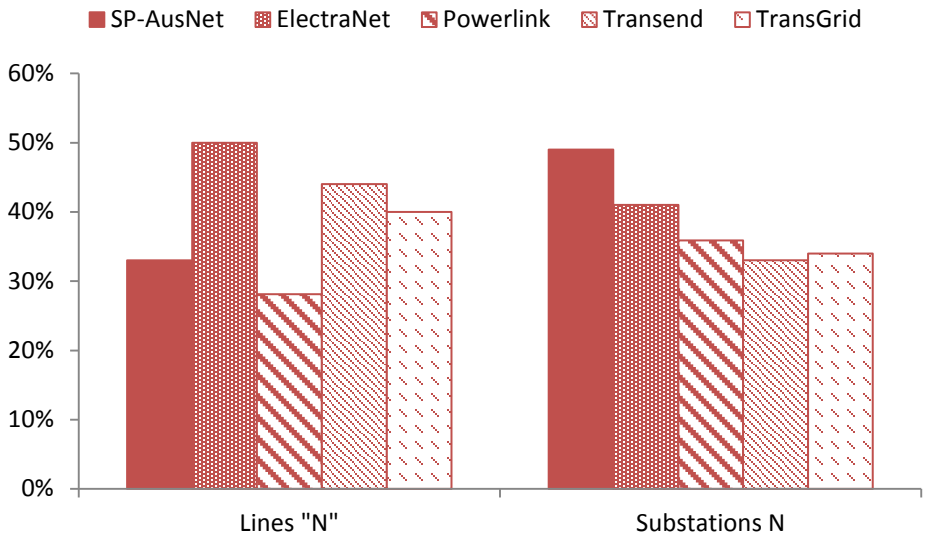
> The difficulties associated with comparing outcomes across transmission networks means that caution is required when comparing the relative performance of

transmission networks. That said, there are a number of shortcomings with the measure of relative utilisation that has been used to test the pressure for augmentation and efficiency of transmission planning across the states.

First, the use of asset utilisation at an aggregate level is misleading and inappropriate. The driver of augmentation expenditure is the utilisation of individual assets. The Evans & Peck's analysis demonstrates that, on an individual asset basis, jurisdictions outside of Victoria have higher utilisation than indicated by AEMO's analysis. (sub. 44, p. 3)

Grid Australia illustrate this point with the use of more detailed asset utilisation data, showing that the utilisation rates of Victorian transmission assets are at times lower (figure 6.8). That is, while Victoria has a higher utilisation rate with regard to substations, the same does not appear to be true for lines. As such, it is difficult to make an overall ranking of state performance.

Figure 6.8 **Transmission asset utilisation**



a Grid Australia also calculated peak and average utilisation for individual circuits and substations. While they had presented the above chart, they noted their general concern in using average utilisation as a benchmark.

Data source: Grid Australia, sub. 44.

The need for analysis of more detailed data is similarly true of distribution networks.[8] Hence, while the analysis in this section may be indicative of the growth

[8] The Commission had also undertaken comparisons of line capacity between distribution networks, using four different sets of conversion factors as set out in Parsons Brinckerhoff (2003, p. 12). The results did not provide consistent comparisons between networks, nor did they provide consistent levels of capacity. Hence, it was not possible to make a sufficiently reliable estimate of line utilisation (a comparison of line capacity and peak load).

of distribution networks in relation to demand, more accurate comparisons could be made if further data were made public.

Are the different approaches efficient?

It is clear that networks have taken different approaches to augmentation and network capacity in recent years. There is a question of whether the levels of augmentation undertaken in states such as New South Wales and Queensland was justified by demand growth, given that Victoria also experienced rising levels of peak demand.

There is also a question relating to where the appropriate benchmark would be for having adequate capacity to keep up with peak demand. What has been deemed reasonable by networks has differed by a wide margin across states. This suggests that it should be possible for some networks to reduce their rate of expansion and still have a level of capacity utilisation that would be within a reasonable range. This question is related closely to the issue of reliability standards (discussed in chapters 14, 15 and 16).

A further question relates to whether it is efficient to continue to build networks to keep up with peak demand. This relates to the drivers of peak demand and the potential efficiency gains of managing demand (discussed in chapters 9, 10, 11 and 12).

6.4 What does the RAB tell us?

The response to rising peak demand is only a partial explanation of why expenditures have risen so rapidly in recent years. Another explanatory factor is that a given amount of capital expenditure does not always translate into a given amount of network capacity. In New South Wales, Queensland and Tasmania, relatively large increases in the RAB during the last regulatory period have resulted in relatively small increases in system capacity (figure 6.9). Hence, there is a dual question of whether the recent extent of physical network augmentation itself was efficient; and whether differences in RAB levels are representative of efficiency gaps.

There are several likely reasons why the recent increases in the RAB have not uniformly reflected the increases in network capacity:

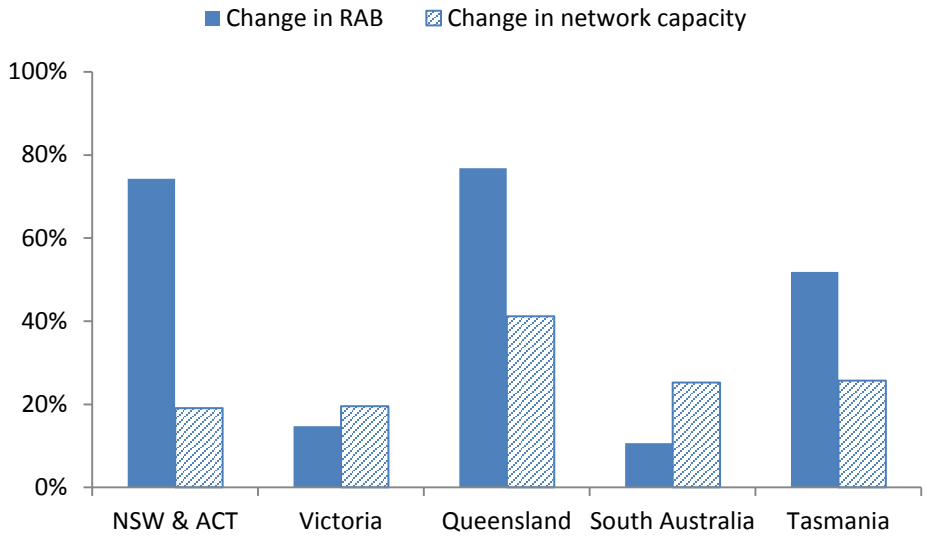
In addition, it would also be more appropriate to use a measure of peak load specific to the distribution area or asset.

- some states have a larger stock of depreciated assets than others. This means that their RAB does not reflect the full scale of their network, and also means that greater replacement capex is required.
- increased undergrounding adds value to the RAB but not necessarily longer lines (and hence is not captured by calculations of network capacity).
- some asset installations may be more difficult and expensive in particular regions.
- some states have made better use of non-network options, such as load shedding control schemes or line uprating opportunities. This includes the real-time rating system in Victoria.

Not all of these factors would indicate inefficiency. With the analysis of more detailed data than is currently available, it would be possible to determine the contribution of each of these factors. It would also help determine whether firms have simply differed in the unit costs of assets and services. On this issue, the AER is currently collecting further data on relevant unit costs.

Figure 6.9 **Percentage changes in RAB and network capacity for distribution networks**

Difference between the opening RAB at the beginning of the previous regulatory period and the opening RAB of the current regulatory period



a Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA).

Data source: AER determinations.

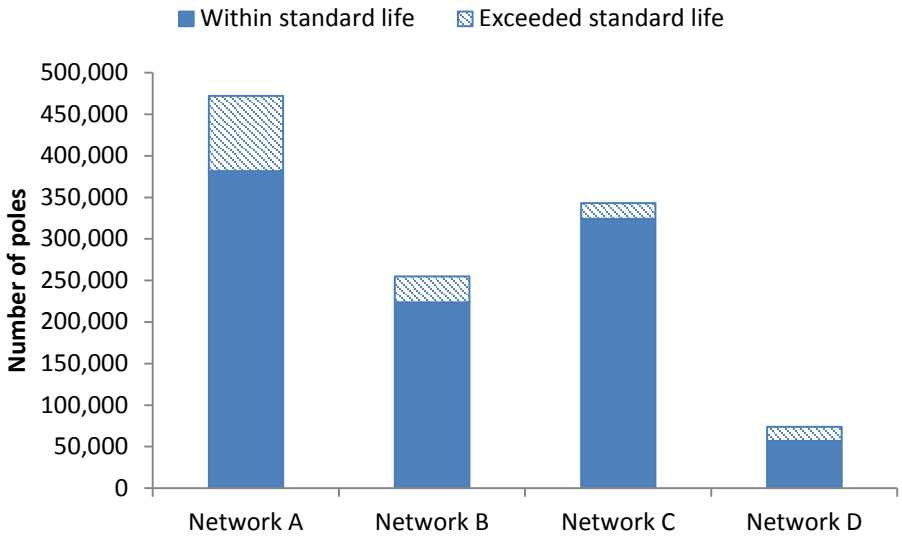
What does the RAB say about efficiency?

The size of a network's RAB is highly relevant to the discussion of efficiency, given that networks are remunerated on the basis of their asset base. However, inferring efficiency on the basis of the size of the RAB is difficult for several reasons:

- The RAB itself is a culmination of various decisions made over time.
- The size of the RAB will be related to many drivers that are unlikely to be influenced by managerial discretion, including the size of the serviced area; aspects of its topology; the number of customers; and levels of demand.
- The RAB is also related to drivers that may or may not be influenced by managerial discretion, such as the levels of network capacity; the types of assets purchased; the prices paid for assets; and the timing of capital expenditures.
- The RAB is depreciated over time, and this can pose a considerable measurement risk where:
  - accounting decisions regarding rates of depreciation are *not* uniform across firms (as is the case among electricity networks);
  - the depreciation of an asset in accounting terms does not reflect its physical or practical depreciation. Many networks have assets still in use which have outlived their standard lives (figure 6.10). The RAB would therefore not account for the ongoing value of these assets, nor their replacement costs. For one distribution company analysed by the Commission, the *replacement value* of assets which had reached or surpassed their standard lives amounted to 20 per cent of their reported asset base (AER unpublished data).

Figure 6.10 **Number of poles that have depreciated to zero[a]**

Approximate number of poles in use that have exceeded their accounting life



a This comparison is indicative only. It assumes that the reported standard life is commensurate with accounting life for depreciation purposes.

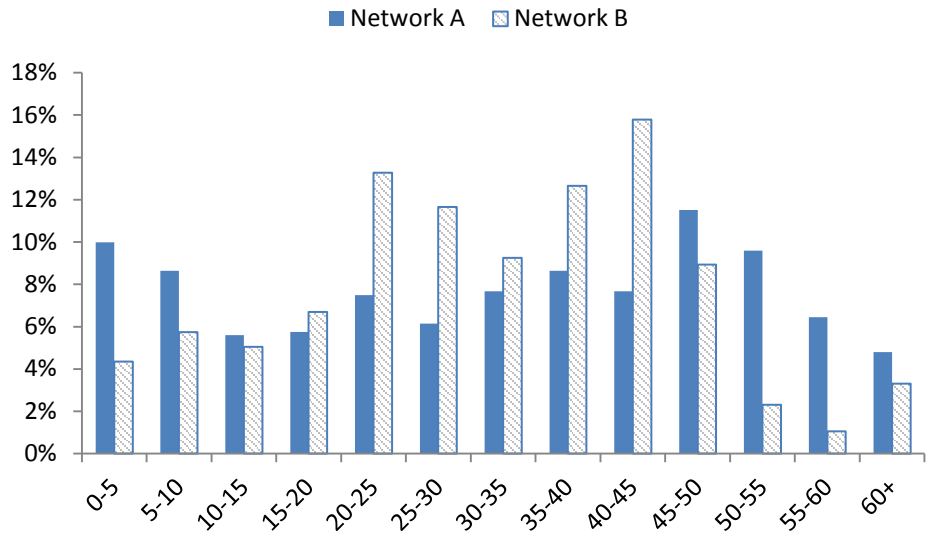
Data source: AER unpublished data.

Replacement capex and asset vintage

An in-depth understanding of asset vintage would not only aid in assessing levels of the RAB, but also in the analysis of replacement capex — though this has been difficult using publicly available data. The AER has only used its replacement capex (Repex) model in determinations for Victoria and Tasmania, and is only beginning to collect data on asset vintage from other networks. Even with data on asset vintage, it is difficult to forecast replacement capex without reliable estimates of standard asset life. Over time, the AER's Repex model will itself improve the accuracy of estimates of asset life.

Asset age distributions differ between networks (figure 6.11). Mountain (2011) noted that privately owned networks tended to have a higher weighted asset age than state-owned networks, and that they should be expected *a priori* to spend more on replacement capex. However, in any given year, the level of replacement capital expenditure is a small fraction of the replacement value of assets that have reached the end of their asset life. Again, this relates to the difference between standard asset lives and the useful life of an asset.

Figure 6.11 **Network assets follow different age distributions**
Age distribution of poles



Data source: AER unpublished data.

Moreover, standard asset lives may be more useful as an indicator of asset replacement for some categories of assets than for others. For example, a network may only have a small number of transformers of a particular category, which makes it more difficult to forecast failure rates. The Commission has also been told by stakeholders that given the high unit costs of transformers, they would be more likely to be replaced based on condition rather than age. An example of how decisions can be made regarding condition-based replacement was given by Ausgrid with respect to the failure of a particular circuit breaker during the previous regulatory period:

> This equipment had been identified for replacement in EnergyAustralia's regulatory submission but rejected by the regulator. Following identification of the failure mechanism, similar defects were found in the remaining population requiring the immediate replacement of all remaining equipment of this type. (Parsons and Brinckerhoff 2012, p. 14)

The timing of replacement capex remains a significant factor in determining the efficiency of network expenditure, and for many networks it has followed a similar trajectory as growth-related capex. For one state-owned network, annual replacement capex was 300 per cent higher in 2010 than in 2000 (figure 6.12). At the same time, demand related capex had grown by a similar scale.

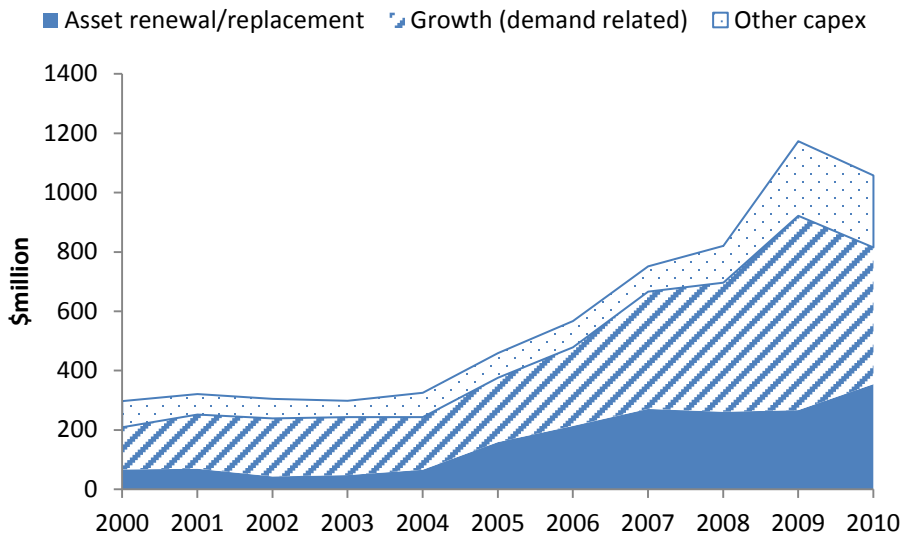
Whereas growth capex may be examined in light of publicly available forecasts of peak demand, the drivers for replacement capex are more obscured. The coincident increases in both replacement capex and growth capex in some networks have led to

significant additional revenue for the network, although there is little independent verification of whether any of the replacement capex could have been deferred.

The overall differences in replacement capex between networks may not be visible for some years. Even if some state-owned networks have replaced assets prematurely, their replacement capex may eventually slow down. Networks that have deferred asset replacement will eventually have to increase their rate of replacement capex. At the very least, benchmarking will be an important retrospective tool for determining whether previous expenditures were premature or excessive.

Figure 6.12 **Breakdown of capex for one state-owned distribution network**

Annual capital expenditure associated with Demand Growth, Asset Replacement, and Other Areas.



Data source: AER unpublished data.

6.5 Expenditure, allowances and timing

As in the case of replacement capex, the timing of capital expenditure more generally has important implications for efficiency. It has been suggested that recent high levels of capex have been partly influenced by time-sensitive incentives. That is, the transitional Rules governing capex overspends allowed for the full rollover of capex into the RAB for the subsequent period (NSW Government 2010, AER 2011a). To the extent that the timing of capital expenditures was brought forward unnecessarily, this would be associated with inefficient investment.

Spending above capex allowances

There is still incomplete information on the overspending[9] of capex allowances for the current regulatory period (where the AER has regulated distribution networks). Nevertheless, there are data for prior regulatory periods, (which were overseen by State regulators), although the availability of data differs somewhat between states.[10]

There is some evidence that above-allowance expenditures have differed between state-owned and private networks. For example, capital and operational expenditure levels for Victorian distribution networks had generally been below both regulatory allowances and network forecasts between 1996 and 2006 (AER 2010b). In comparison, all of the NSW distribution networks had exceeded capex allowances between 1999 and 2004 (IPART 2004).

During the regulatory period immediately prior to AER regulation, capital expenditure exceeded allowances by a significant amount, particularly (but not exclusively) for state-owned distribution networks (figure 6.13). As the NSW Government (2010) noted:

> The [NSW distribution and transmission network] businesses overspent by about $1.4 billion in the previous price period with more than half the overspend occurring in the final year (2008/09) … All businesses have spent less than their capital expenditure allowance in 2009/10. (p. 33)

The evidence suggests that many businesses had overspent, but particularly so as the regulatory period progressed.

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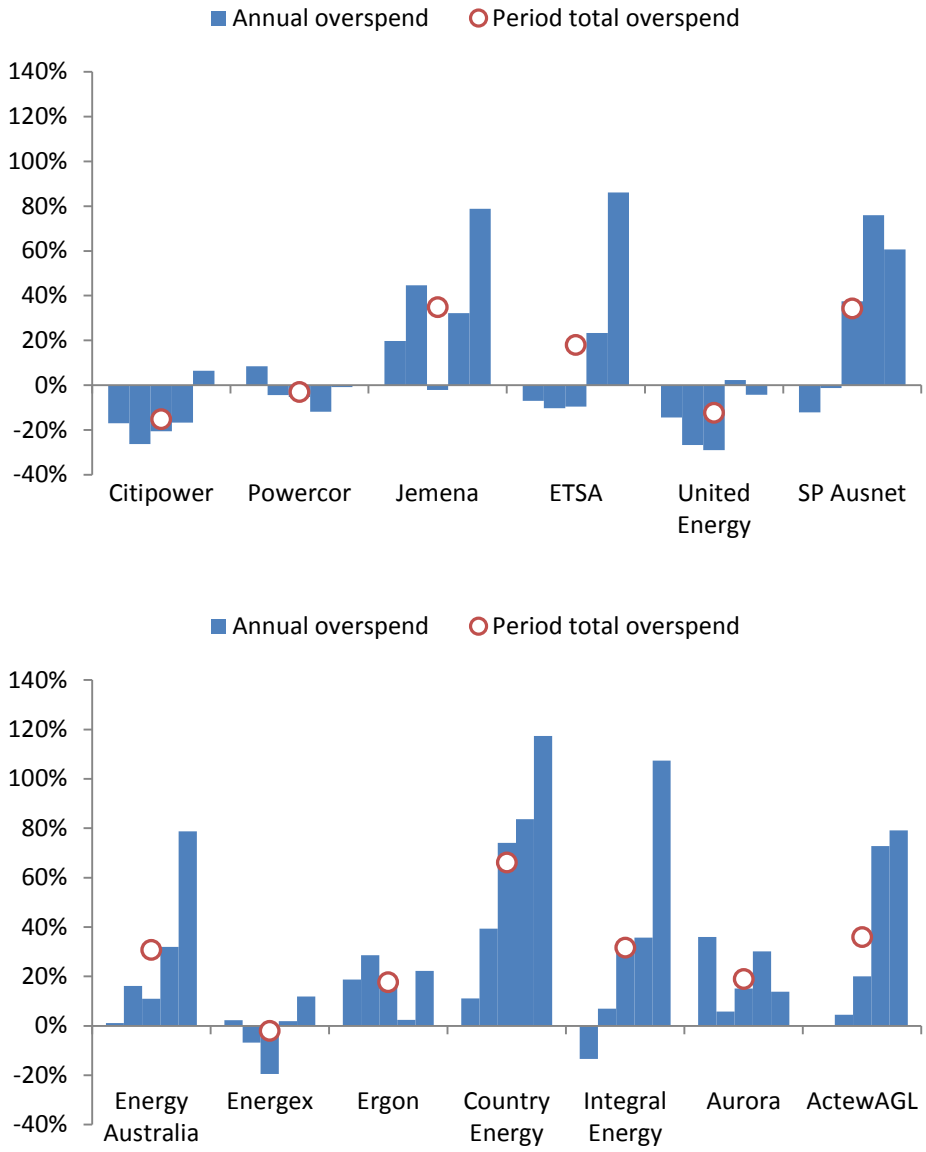
9 In this section, the term 'overspending' is not intended to imply that the expenditure is prima facie inefficient. The term is used is used in a similar vein by Parsons Brinkerhoff (2012).

10 There have also been some discrepancies between the data published on capex overspends. For example, the capex overspends reported in figures may not be directly compatible between AER (2010b), Jemena (2009), AER (2012b) or Parsons Brinckerhoff (2012). Further data on actual expenditure held by the AER were considered confidential. As such, the Commission has made indicative comparisons based on the available data.

Figure 6.13 **Annual capital expenditure above allowances in the period prior to AER regulation**[a]

Actual capex as a proportion of capex allowance



a This graph shows the pattern of actual expenditure over time relative to regulatory allowances in the regulatory period immediately prior to the AER's commencement as the distribution network regulator. For each firm, the graph includes observations from the five years immediately prior to the AER's commencement as the distribution network regulator. The graph does not distinguish between cost-pass through events and other overspends.

Data source: *Data source*: Parsons Brinckerhoff (2009a, 2009b, 2010, 2012); Jemena (2009); Wilson Cook (2008); AER (2010b).

There are several factors that may contribute to the overspending of capex allowances, some of which network business could not control. For example, new licence conditions relating to planning criteria and reliability were introduced in 2005 for NSW networks (discussed in chapter 16) — this was associated with a cost

pass-through provision that accounted for around half of the overspend by NSW distributors (Wilson Cook 2008, Parsons Brinckerhoff 2012). As such, much of the overspend was due to decisions by the NSW Government rather than the networks.

To some degree, however, overspends appear to subject to operational decisions by networks, as described by Ausgrid for example:

> A major contributor of the overspend in the [2004-09] period was the decision by the business that it was necessary to address asset replacement needs over the period, despite insufficient funding being provided for this purpose by the regulatory determinations. (Ausgrid as quoted by Parsons and Brinckerhoff 2012, p. 14)

To the extent that allowance overspends result directly from network decisions, the overspends should be considered in light of the prevailing incentive framework.

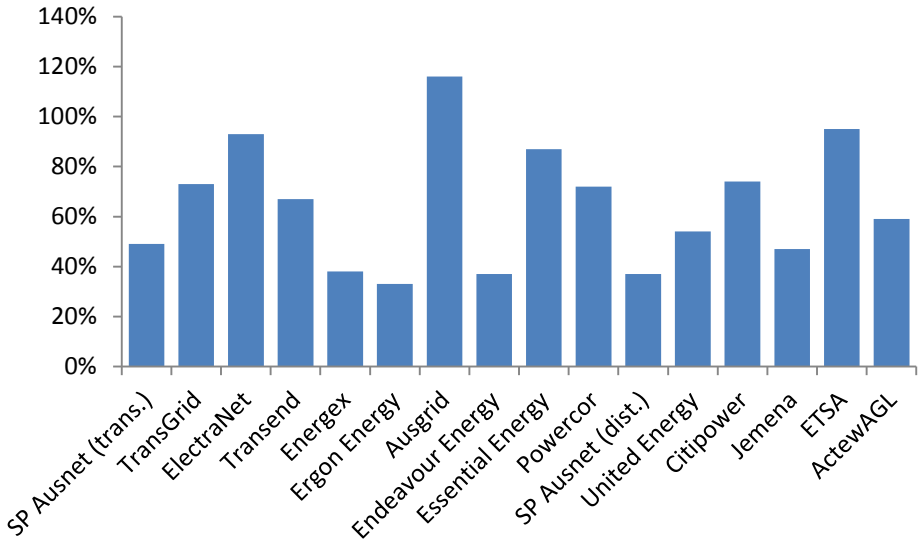
The AER (2011a) estimates that the above-allowance expenditure in New South Wales and Queensland accounted for roughly 25 per cent of the subsequent price increases. Furthermore, high levels of expenditure also influenced subsequent determinations by the AER, as network forecasts were based on actual expenditures in the previous periods (figure 6.14). Where evidence is lacking in a determination, an emphasis is sometimes placed on historical trends:

> There is little information presented that supports the scale of the increase in the current period. … That said, given that the next period appears to be broadly in line with the historical trend (2006-2008), the forecast for the next period is not unreasonable. (Nuttall 2010 p. 196)

These findings appear to be consistent with inefficient overspending induced by the flaws in incentive regulations discussed in chapter 5.

Figure 6.14 **Increase in network forecasts relative to previous period actual capex**

Percentage difference between network forecasts of capex and the actual capex in the previous period



Data source: AER (2011a).

6.6 Public and private ownership

Chapter 5 points out that state-owned businesses often face weaker incentives than private businesses to control costs. The empirical evidence discussed in this chapter generally suggests that there are differences in the way private and state-owned businesses operate. For example:

- State-owned businesses in New South Wales and Queensland have increased their capital expenditure to levels well above those of private firms in Victoria for a given level of peak demand.
- State-owned businesses have had relatively large increases in the RAB for a given increase in network capacity.

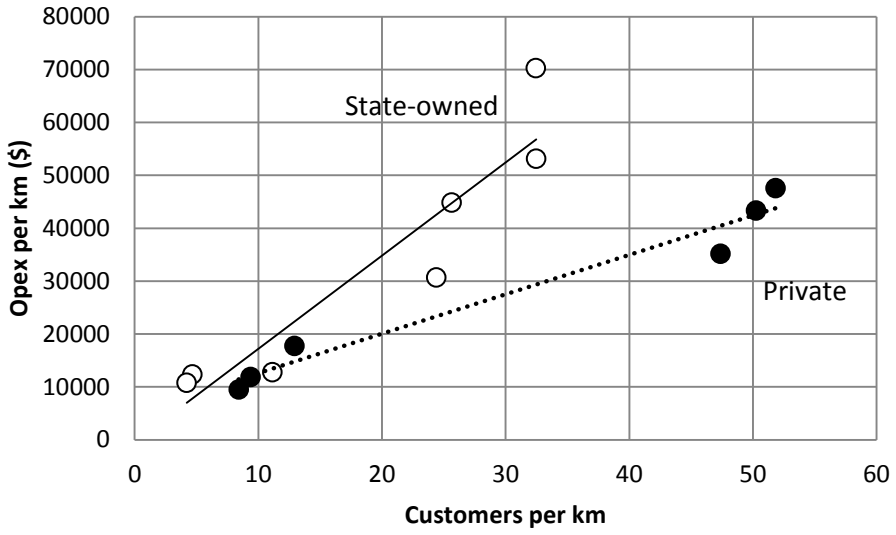
While these points are not proof of inefficiency, it is unclear whether the scale and timing of the expenditure has been entirely justified.

More specific analysis of expenditure further illustrates the divergence between private and state-owned firms, such as the relationship between expenditure per circuit km and customer density (figure 6.14).[11]

11 Similar trends are observed for capex.

Figure 6.15 **Opex and customer density for state-owned and private firms**

Opex per km by customer density for distribution networks

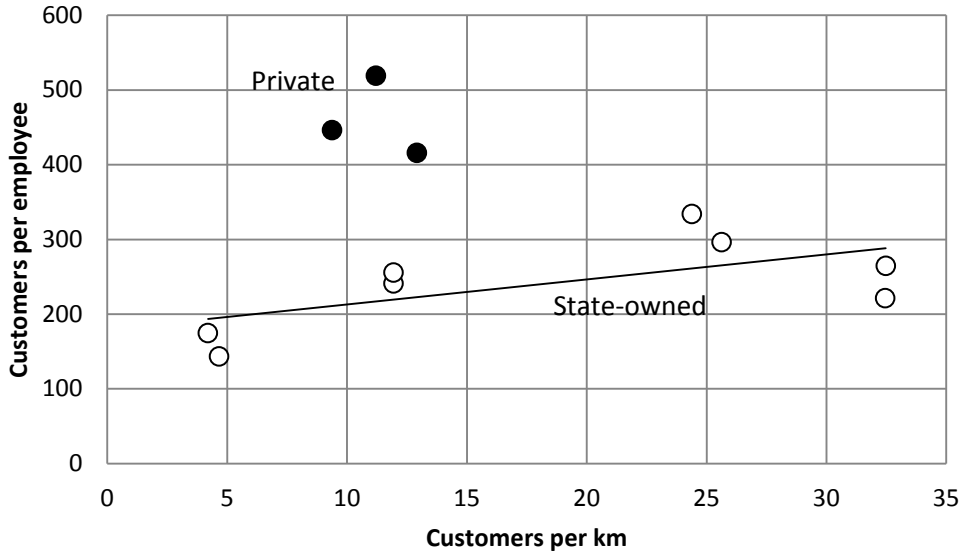


Data source: AER (2011b).

The available evidence also suggests that operational practices differ between state-owned and private networks. For example, state-owned networks generally have a lower ratio of customers per employee after accounting for customer density (figure 6.15). During the previous regulatory period, staff numbers for the NSW networks rose by 42 per cent (NSW Government 2010). Some increases in the labour force of the New South Wales and Queensland networks reflected increases in capital works over recent years.

The share of in-house labour to contractors also seems to differ between state-owned and private firms, with the ratio being much lower for some private firms (figure 6.16). That is, expenditure on labour, materials and contractors (LMC) is allocated to both capex and opex. None of the state-owned networks spent less than 13 per cent of LMC capex on in-house labour, which was the average share spent by private firms. State-owned networks also spent an average of 47 per cent of LMC opex on in-house labour, compared to 32 per cent for private networks. This suggests that some operational and labour practices may differ between state-owned networks and profit-motivated private networks.

Figure 6.16 **Customers per employee[a]**

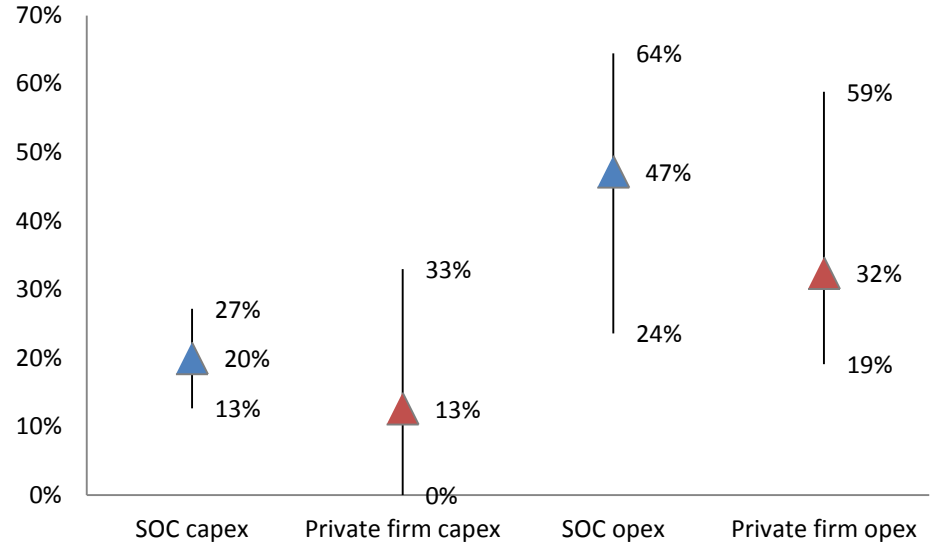


[a] For firms where data is available. Unlike data collected by regulators, figures included in annual reports are often representative of an entire company rather than for the distribution business alone.

Data source: Network annual reports.

Figure 6.17 **Relative importance of in-house labour compared to materials and contractors[a]**

Range and averages for state-owned corporations and private firms



[a] Expenditure on in-house labour as a proportion of the total expenditure on labour, materials and contractors. Highest and lowest firm results are presented, as well as group average.

Data source: AER unpublished data.

6.7 Conclusions

The empirical evidence based on the best available data shows that performance, as measured by a number of indicators, varies significantly between networks. This is unsurprising, as previous benchmarking studies have concluded that some networks perform more efficiently than others. More detailed data would be useful in quantifying the impacts of various drivers (improvements to data access are discussed in chapter 8).

The evidence suggests that both network expenditures and the WACC have had a significant effect on network revenues. To the extent that the WACC has been a driver, the efficiency of overall network revenue outcomes will depend partly on the processes involved with setting the WACC.

Network revenue outcomes are also heavily dependent on the various investment decisions made by networks. For example, networks tend to differ significantly in regard to capacity utilisation, and in recent years, some networks have expanded their network capacity relative to peak demand while others have not. Capital expenditures have also differed by a wide margin, although this relates to scale of both augmentation and of asset replacement.

Whether the various levels of expenditure have been efficient may depend on further information, such as the engineering justification of particular capital works and on longer-term comparisons between firms. However, from the high-level evidence analysed in this chapter, it appears that the levels of expenditure observed for some networks are not easily justified by the available data. Where firms have overspent regulatory allowances (and in some cases, may have profited from it), there is uncertainty about whether that expenditure has been reasonable. Furthermore, the timing of capex overspending is consistent with suggestions that some inefficiency has been induced by flaws in incentive regulations. Still, the Commission has not presented a single definitive quantification of the efficiency gaps between networks.

Several issues raised in this chapter warrant further consideration:

- The significant impact the WACC has had on network revenues warrants particular attention, not only with regard to the methods used in calculation (chapter 5), but also in the role of the Australian Competition Tribunal in determining it (chapters 5 and 21).
- Reliability standards have had a significant effect on expenditure levels, particularly in NSW. These standards will continue to influence the way in which networks respond to increases in peak and average demand. As such, it is

necessary to consider whether these standards are set efficiently, and whether the resulting costs of augmentation are commensurate with value of reliability for consumers (chapters 14, 15 and 16).

- Network decisions on expenditure are also subject to the various incentives inherent in the regulatory framework (discussed in chapter 5). These incentives are particularly relevant to network forecasts of demand and the timing of expenditure. There is potential to improve the regulatory incentive framework, particularly through the use of benchmarking (chapters 5 and 8). Beyond this, networks may also be able to play a larger role in influencing the actual rates of peak demand — to this extent, demand side policies should also be investigated (chapters 9, 10, 11 and 12).
- While firms have taken different approaches to network capacity, the networks that have undertaken the most rapid expansion have been under state ownership. The potential issues with public ownership more generally, are discussed further in chapter 7.

7 Ownership

Key points

- While governments have a legitimate role in owning and operating many services in Australia, the rationale for state-ownership of electricity network businesses no longer holds.
- This reflects the development of sophisticated incentive regulations that function best when the regulated business have strong profit motives.
  - State ownership produces perverse interactions with the existing Rules, which are likely to lead to overinvestment and ineffective cost controls.
- State governments often impose multiple constraints on state-owned corporations that are incompatible with their central purpose of maximising returns to their shareholders. These constraints include:
  - social and environmental obligations
  - requirements to procure locally
  - requirements to reduce returns to restrain prices
  - requirements to limit capital spending when governments are concerned about debt levels
  - employee benefits and job security for employees are out of kilter with those associated with most businesses
  - poor governance.
- The evidence appears to suggest that state-owned enterprises are less efficient than their private sector peers.
- The best remedy is privatisation. However, in the event that governments do not privatise their state-owned network businesses, the original intent that they act as truly independent corporate entities should be reinstated, with their governance and statutes changed to give effect to this clearer role.

Governments have a justifiably central role in the direct supply of many services in Australia. This chapter explains why this no longer holds for the provision of electricity network services. Yet, Australian governments currently own about 75 per cent of electricity network assets in the NEM and a greater share for Australia as a whole (chapter 2).

Section 7.1 sets out a simple framework for making coherent choices about ownership, and explains why the circumstances that would justify government ownership are no longer present for electricity networks.

The regulatory incentive arrangements for the NEM were designed to encourage cost minimisation by profit-maximising businesses. The implicit assumption was that corporatised state-owned businesses resembled private entities and that they would behave the same way. That does not appear to have occurred. Drawing on chapter 5, section 7.2 explains why incentive regulation is more compatible with privately-owned enterprises.

Notwithstanding the removal of state-owned electricity network businesses from direct government control, as shareholders, governments still have mixed incentives. They have imposed a range of non-commercial objectives on their businesses. These increase the costs of those businesses and, in some cases, send mixed messages to managers about their priorities. Section 7.3 considers such mixed objectives, as well as examining some of the government constraints and poor governance arrangements in state-owned corporations (SOCs) antithetical to desirable commercial practices, and to the delivery of the National Electricity Objective — efficient operation of, and investment by network businesses for the long term benefit of consumers.

An important question is whether the deficiencies in governance and weaker incentives for cost minimisation are revealed in lower productivity rates or in other performance measures. Section 7.4 examines this question, drawing on the findings of chapter 6, some recent judgments by other reviews, and the findings of the international literature on the effects of government ownership.

7.1 A framework for considering ownership

Australian governments 'own' many organisations responsible for producing goods and services. They play a dominant role in parts of the economy where people do not pay directly for the services — defence, policing, courts, customs, foreign embassies, policy formation, the tax office, government schools and public hospitals. On the other hand, governments have relinquished their role in many activities funded by customer charges, such as banking, telecommunications, airlines, airports, publishing, manufacturing, private schools and private hospitals (and in the more distant past, fish and butcher's shops, building workshops and brickworks — Goot 2010).

Nevertheless, governments are still often owners of utilities — exemplified by water and electricity networks.

The question is where it is appropriate for governments to act as owners of *anything*, and to assess whether these circumstances apply to electricity networks. The strongest (sound) rationale for government ownership is where governments find it difficult to write good contracts with private businesses or to regulate them effectively *and* where those contractual problems can be effectively overcome through government ownership.[1] This may occur in several circumstances:

(i) Businesses may sometimes produce social goods or bads, as well as the goods they sell on markets. From the community's perspective, the goal should be to maximise the net value of the private and social goods (King and Pitchford 1998). For example, a national park earns market income from entry fees, but they also have major non-economic roles, such as preserving species and undertaking research. In theory, a government could contract these non-market activities to private businesses, or regulate the businesses so that they are obliged to provide them. However, it may be hard to verify whether the business has fulfilled its side of the bargain given the difficulties of measuring the outputs. In that case, a private business has an incentive to make higher profits by producing less than the desirable amount of the non-market output. A government-owned business does not have any such incentive, since it does not keep any surplus as a private return.

(ii) Government ownership may be preferred to procurement from private parties if it is difficult to write a contract that reflects government's changing preferences and priorities. This is similar to the considerations of private businesses when deciding how much to outsource an activity or undertake in in-house.

(iii) Quality and performance may be higher where an employee has a motivation beyond their pay and conditions to achieve a goal common with the objective of the organisation. For example, this may be an idealistic teacher that puts effort into less able students or a solider fighting for their country (Besley and Ghatak 2005).

(iv) There may be intrinsic conflicts of interest in private ownership. One US economist posed the question of whether a private business could run the US

[1] Some may propose broader arguments for government ownership — such as social norms about what the community should own collectively and what should be held in private hands. However, beyond assertion, it would be difficult to verify when those circumstances arise. Regardless, for the present purposes, it would be hard to argue that government ownership of wires and poles meets an Australian social norm.

State Department. The answer was (obviously) no, but as Dixit (2002) explores in some detail, the fundamental reason centres on the difficulties in creating appropriate incentives, monitoring performance, ensuring probity and motivating employees

(v) Government-ownership might be an alternative to regulated private enterprises — especially in the provision of essential services — if it is difficult to construct effective regulations. In that instance, government ownership might result in outcomes closer to the competitive ideal (Goot 2010 and Yarrow 2012a, p. 3).[2]

In the case of electricity networks, it is less clear that (i) to (iv) has ever applied as a legitimate basis for state ownership of electricity networks. However, a good case could be made that (v) was relevant prior to the development of sophisticated competition regulation. There is also a view that state ownership was important to achieve social goals that were fluid and implicit.

However, circumstances have changed with several major developments:

- Australia has an elaborate system of regulatory arrangements for controlling prices and ensuring quality of services in network businesses, underpinned by independent regulators. Ownership can no longer be seen as a substitute for regulation.
- All the state-owned businesses have now been corporatised, so that they are at much greater arm's length from government than they were in the past (though, as discussed later, not as distant as desirable). In that case, to the extent that they ever existed, rationales (i) to (iv) can no longer apply, since the contractual difficulties between government and a corporatised entity are similar to those between a government and a private entity.

Accordingly, the rationale for state ownership has now disappeared. That might not matter much if corporatisation of government owned businesses had created sufficient incentives for cost-minimisation. If corporatised entities behaved like private businesses, then even if their ownership status were no longer justified, the transactions costs of privatisation might mean that they should remain publicly-owned. However, as the remainder of this chapter shows, the premise that they do or can behave like private businesses is doubtful.

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2 While in some instances, state-ownership has served as an *alternative* to a regulated private monopoly, in many others, entry by state-owned businesses was apparently intended to ensure adequate investment and to intensify competition in what remained largely private markets. This was an important driver of state-ownership in the first half of the 20th century (Goot 2010).

7.2 Incentive regulation and state-owned corporations

Incentive-regulations are built on a simple premise. Where the regulatory rewards to the business are (at least significantly) separated from their actual costs, profit-motivated businesses face strong incentives to cost minimise in any given period. Over time, the regulator can reign in the rents this creates by raising the performance benchmark.

However, as discussed in chapter 5, the investment incentives for state-owned corporations are more complex than for privately owned businesses, and can work against the cost minimising incentives in the regulatory regime. Without repeating the analysis in that chapter, this reflects several factors:

- Finance appears to be easier to access for SOCs than private businesses (certainly over recent times). The consequence is that, in comparison with private businesses, the weighted average cost of capital (WACC) actually facing SOCs is more likely to be lower than the regulated WACC. The larger the gap between the 'true' and the regulated WACC, the weaker is the penalty from overspending. Indeed, a large enough gap can make it profitable to overspend. This effect is accentuated by the fact that state governments are effectively able to receive a pre-tax rate of return on their SOC investments because they receive the company taxes that would otherwise have gone to the Australian Government. This could weaken the usual incentives of shareholders to constrain overinvestment. It would also mean that setting a higher reliability standard (with its associated requirements for additional investment) could produce positive financial returns.
- Financial market accountability is concentrated in just one party (the government). In contrast, private businesses must typically secure their equity or debt from multiple parties, all of which monitor the business for its performance when deciding whether to provide finance. The consequences of poor management by a private network business— and the reputational effects that ensue — are likely to have enduring effects on the capacity of the business to obtain further capital (and on the cost of that capital).
- Insolvency is effectively impossible.
- Governments have non-commercial incentives that constrain their SOCs — an issue examined further in section 7.3.
- Governance arrangements may not encourage tough-minded management (also considered further in section 7.3).

The Commission's diagnosis on the above is not new, with many others having identified the mismatch between incentive regulation and state-ownership of

electricity network businesses.[3] The most recent consideration of these issues concluded that the current regulatory regime is essentially incompatible with state-owned businesses:

> The NER and NGR are based upon an economic approach developed for the regulation of privately owned utilities. Whilst the approach can, and has, been applied to state owned entities, international experience tends to indicate that it is more difficult to get to work effectively. Underlying issues include a relative lack of incentives to reduce costs in publicly owned monopolies, and intra-government conflicts relating to the supervision of publicly owned monopolies (most typically between that part of government responsible for performing shareholder functions and the regulatory authorities). (Yarrow et al. 2012a, p. 121)

More generally, Yarrow (2012) has emphasised that while the interactions of incentive regulations with private utilities are relatively predictable, this does not hold for state-owned network businesses. In commenting on the problems apparently besetting the National Electricity Rules, Yarrow drew some parallels to the experiences of the Island of Guernsey to provide a lucid illustration of the difficulties in this area (box 7.1).

Collectively, these factors suggest weaker incentives for cost controls in state-owned businesses, a position endorsed by some privately-owned businesses:

> The Businesses believe that privately-owned businesses have stronger drivers to operate efficiently and to respond to the incentive arrangements provided in the current Rules than publicly-owned businesses given the nature of private shareholder requirements. This has been borne out by the experiences of privatisation in Victoria and South Australia. … The Businesses support the privatisation of the publicly-owned DNSPs in NSW, Queensland and Tasmania and believe that it presents significant opportunities to achieve efficiency savings, which will be beneficial to end customers through lower distribution prices. (ETSA, CitiPower and Powercor Australia sub. 6, pp. 41–42).

The Commission has recommended amendments to the Rules that would partly address some of the above concerns. For example, greater ex post scrutiny and potential rejection of capex overspending by the AER is likely to mainly apply to SOCs (where overspending has been more common — chapter 6). However, as noted in chapter 5, other measures, such as using a different WACC are not practically feasible. It is not sensible to craft new Rules whose purpose is to address the distortions created by government ownership of some utilities.

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[3] These include Biggar (2011b, pp. 14ff); the Energy Users Association of Australia (EUAA 2009, p. 1); Mountain and Littlechild (2010), Mountain (2011); the NSW Commission of Audit (2012, p. 204); and an IPART paper by Cox and Seery (2010, p. 22).

Box 7.1 **Lessons from the Island of Guernsey**

In a detailed micro study of competition regulation on the Island of Guernsey, two leading competition economists found that standard incentive regulation worked reasonably well for the privately owned telco sector, but poorly for the publicly-owned postal and electricity sector. In the latter instance, the problems centred on:

- a relatively inactive shareholder
- the capacity for the business to retain earnings for discretionary investment at a time of its choosing
- a flawed appeal mechanism
- perhaps most oddly, the fact that there were implicitly two incompatible regulatory systems sitting next to each other. On the one hand, there was an independent regulator charged with the usual responsibilities for setting efficient prices. On the other, the electricity business had, in effect, its own regulatory charter. It was obliged to balance its commercial objectives against the effect on the community of any increase in its charges.

Guernsey's arrangements are therefore unique, especially in light of the latter point.[4] Nevertheless, Guernsey is an interesting case study of the importance of the confusions that arise when a regulatory regime intended for profit-minded managers is applied to a business that has non-commercial objectives.

Source: Yarrow and Decker (2010).

7.3 Non-commercial imperatives and interference

In contrast to privately owned businesses, state-owned businesses are exposed to many government requirements, including non-commercial goals, ministerial directions, and obligations for local procurement and greater employment benefits. Arrangements vary by jurisdiction.

Multiple and conflicting objectives affect some businesses

Several jurisdictions explicitly include multiple objectives in the Acts governing the conduct of their SOCs. For instance, in NSW, s. 8 of *The State Owned Corporations*

4 In Australia, there can still be tensions, albeit of a different form. The AER acts as the regulator of network prices, while state-based regulators still regulate retail prices (though this is due to change). State-based regulators may bring (government-mandated) non-commercial considerations to their determinations of retail prices (for example, QCA 2012), while the AER is purely an economic regulator.

Act 1989,[5] requires state-owned corporations to give equal weight to commercial success, social responsibility, ecological sustainability, and a sense of responsibility towards regional development and decentralisation. The legislation for Australian Capital Territory-owned corporations appears to be modelled on the NSW Act, with requirements for management to give equal weight to a range of commercial and non-commercial obligations.[6]

The statutes for Queensland's SOCs appear to be less in conflict with commercial behaviour. Commercial success is the prime goal, and as a principle, businesses must not have conflicting goals.[7] Any community service obligations (CSOs) of the business must be clearly identified in the business's statement of corporate intent and separately costed (with the business to be 'appropriately compensated for its community service obligations and any funding will be made apparent'). One of the advantages of explicit budget-funded CSOs is that they increase shareholder pressures for business performance. The Queensland Commission of Audit (2012, p. 165) noted that the CSO for Ergon Energy (the regional distribution business in Queensland):

> …represents a significant funding risk to the State, which highlights the need for appropriate incentives for Ergon to contain costs and manage its business appropriately in order to limit the State's financial exposure.

The virtues of transparency aside, the Queensland Commission of Audit (2012, p. 159) noted the Queensland Government still has the potential to issue non-commercial directives (discussed further below). It also found 23 other policies and guidelines for SOCs outside the Government Owned Corporations Act, indicating the challenges for management in running their business on a purely commercial basis.

In Tasmania's case, SOCs must, on the one hand, operate in accordance with sound commercial practices and as efficiently as possible, yet also 'have regard' to the economic and social objectives of the state.[8] The treasurer has the power to specify the economic and social objectives of the state relevant to any SOC (but must do so transparently by gazette).

There is some evidence of tensions between these commercial and non-commercial objectives. The final report of the Independent Review of the Tasmanian Electricity Supply Industry (Electricity Supply Industry Expert Panel 2012a), noted:

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5 These multiple objectives are repeated in the *Energy Services Corporation Act 1995 (NSW)*.

6 S. 7 of the *Territory-owned Corporations Act 1990*.

7 S. 16 (a) Principle 1 of the *Government Owned Corporations Act 1993 (Qld)*.

8 s. 7(1)(i) of the *Government Businesses Enterprises Act 1995*.

> Stakeholders from the SOEBs [state-owned electricity businesses] indicated that they have difficulties in resolving the inherent tension between their obligations under legislative and other instruments to act commercially on the one hand, and the expectations that the Shareholders may or may not have explicitly stated with regard to delivering broader policy objectives (for example reducing the impact on cost of living for customers or the retention of members of the local Tasmanian workforce as employees of the businesses). (p. 47)

Interestingly, that report also observed:

> The CSO [Community Service Obligation] process is a key component in minimising the potential disconnect between directors' duties and the legislative framework on the one hand and the delivery of broader policy objectives on the other. (ibid, p. 60)

But that process often fails:

> The Panel has observed other examples where the CSO framework has not been deployed where it would have been appropriate to do so. For instance, in 2009 the Government wrote to Aurora Energy to express a desire for tariff increases charged under the Aurora Energy Pay as You Go (APAYG) billing system to be effectively 'capped' for concession cardholders at a rate below that at which Aurora Energy was intending to charge. (ibid, p. 61)

Rod Sims (2012b), chair of the ACCC, summarised the dilemma:

> We still have key network businesses in Government hands in Tasmania, Queensland, New South Wales and Western Australia. Good regulatory policy is important, but regulation is not a substitute for good governance. The incentives of Government shareholders are unavoidably mixed and complicated by multiple and disparate objectives. (pp. 4–5)

If state-owned businesses are not privatised, the original intent of corporatisation should be re-instated, with the businesses purely oriented to commercial purposes. Any non-commercial objectives of government should be separated from ownership, and independently financed. If such objectives are maintained, they should be prioritised and the business given guidance on their application. Given the tendency for weak or changeable shareholder disciplines, it would be appropriate to specify expectations of equity and dividend returns that the boards and management of the state-owned enterprises were expected to achieve, commensurate with those considered acceptable by an independent investor.

Procurement policies

SOCs face several obligations to meet procurement guidelines set down by their governments.

The NSW Government's procurement policy — the Local Jobs First Plan — includes two mandatory components to address industry development for purchases made by NSW Government agencies, including SOCs (NSW Government 2009). Consistent with the NSW Government's international obligations, such as Free Trade Agreements, the beneficiaries are limited to small and medium enterprises (ibid, p. 4). This suggests that the agreements are seen as risking violating the principles of free trade.

The plan includes various price preferences:

- The Country Industries Preference Scheme is applied to support approved manufacturing industries in country New South Wales by adding margins of 2.5 per cent or 5 per cent only to the prices of other New South Wales suppliers.
- The Australia and New Zealand (ANZ) Price Preference Margin provides for a 20 per cent price discount to be applied to that part of the tendered price related to the ANZ content of goods and services offered in a tender response.

It also requires tenderers to draw up industry participation plans. For contracts over $4 million, that would require the tenderer to indicate the consequences of it winning on the number of existing and new employees engaged in delivering the contract and their location; the number of local suppliers that will win work as a result of the contract and their employment numbers; the number of apprentices and trainees supported by the contract; and the regional economic impact, skills enhancement and technology transfer that will result.

Queensland state-owned network businesses are subject to similar provisions as part of the government's *A Fair Go for Local Industry* policy (Queensland Government 2008, 2011). For example,

> … as part of value for money due consideration in the tender evaluation is given not only to price but also to environmental sustainability, quality and delivery, whole-of-life costs and/or administrative and risk mitigation advantages *and the advancement of the priorities of Government arising from local sourcing* [our italics]. (Queensland Government 2011, p. 5)

Less intrusive procurement policies appear to be in place in the ACT and Tasmania.

Such procurement arrangements increase input costs and create compliance burdens for state-owned network businesses. In this regard, it was notable that the Ausgrid board assessed their obligations under the Local Jobs First Plan as non-commercial, noting that:

> The costs of complying with that policy have not been separately funded, although the direction was given to implement the plan by the Minister (Ausgrid 2011b, p. 10).

EnergyAustralia (the predecessor to Ausgrid) estimated that complying with the Plan would cost them $6 million in 2011-12, rising to $50 million per annum by 2015-16 (Industry and Investment 2010, p. 25). These costs will not be reflected in electricity bills since they do not meet the AER's guidelines, but they will affect dividends to the New South Wales Government. They are indicative of the problematic links between state-owned corporations and government.

Employment policies

Employment policies for the state-owned utilities have several distinct features. First, they appear to pay higher wage rates than private utilities (chapter 2).[9]

Second, they provide greater protection for their workers from structural changes in their businesses. The Queensland Commission of Audit of state-owned enterprises (2012, p. 159) noted that restructures of various government-owned corporations (such as ports and electricity generators) included amendments to enterprise bargaining agreements safeguarding employees from forced redundancies and forced relocations for a period of three years after the restructures. As a result, the Commission of Audit observed that the enterprises were unable to rationalise their workforces in response to changed asset portfolios. Instead, the businesses were required to incorporate excess staff across their respective organisations, with associated inefficiencies. While Queensland networks businesses have not been re-structured, these other instances reveal that the Queensland Government has placed significant weight on matters that would usually be left to routine industrial relation practices (or otherwise through generic employment assistance measures). In addition, the provision of such safeguards is likely to weaken the incentives for employee efficiency in any of the state-owned corporations.

In NSW, Ausgrid is required to provide a five-year employment guarantee to award staff or separate senior contract staff in accordance with their contracts, a requirement that came into play following the separation of the retail arm from Ausgrid (2011b, p. 7).

Some have raised concerns about the use of overtime. The NSW Government's economic development agency, Industry and Investment (2010, p. 50), observed that overtime levels were projected to rise significantly (and over 100 per cent in a

[9] While these data relate to electricity, gas and water utilities as a whole, other evidence corroborates the likelihood that network business wages and salaries have been rising. The NSW economic development agency, Industry and Investment (2010, p. 29) noted that NSW network businesses' wages increased faster than the NSW average from 2004-05 to 2009-10.

single year for one business). It identified this as an area for possible cost containment.

Sponsorships

While relatively small in scale, sponsorship behaviour provides a revealing window on some of the differences between state-owned and private network businesses.

There are instances where SOCs have provided community sponsorships and donations that appear to be of a magnitude at odds with the goals of most commercially-oriented businesses. It is particularly hard to characterise such sponsorships as building a brand name to attract customers, since customers have no choice but to deal with them.

For example, in 2010-11, Ausgrid provided $4.3 million in sponsorship (but including employee payroll contributions) to various community groups, including around $500 000 to the Sydney Symphony Orchestra. The NSW Government recently required that Ausgrid to terminate this and other sponsorships (Hartcher 2012). The level of sponsorship is relatively large and at odds with the sponsorships generally provided by most other network businesses (as shown below). Moreover, the directive from the relevant minister to cease the sponsorship reveals the capacity for the government to direct the management of ostensibly independent corporations.

The AER rejected Energex's proposed $9.1 million of sponsorships over the 2010-11 to 2014-15 regulatory period, noting:

> However, in general the AER considers that sponsorship activities do not represent expenditure required to comply with the opex objectives. The AER considers that sponsorships are generally designed to increase brand awareness or demonstrate community support. Such activities may provide a benefit to the community but do not relate to the provision of standard control services by regulated electricity DNSPs, nor do they relate to the opex objectives. The AER considers that Energex has not demonstrated how its $9.1 million forecast sponsorship expenditure is required to achieve the opex objectives, nor has it outlined how it is relevant to the provision of standard control services. The AER is not satisfied that this forecast level of expenditure is efficient and prudent expenditure. (AER 2009c, p. 648)

In contrast, other SOCs had levels of sponsorship more commensurate with private network businesses (though still on average higher), recognising that it can be in the interests of a business to build its community standing. For example, sponsorship amounts for the various businesses in 2010—11 were around $300 000 (Transgrid — SOC), $600 000 (Endeavour Energy — SOC), $1 100 000 (Ergon Energy – SOC); $500 000 (Aurora Energy — SOC); $170 000 (SP Ausnet — private);

$200 000 (Jemena — private); and $125 000 (Citipower and Powercor, including employee donations — private). These sponsorships are not included in allowable revenues.[10]

Political Intervention

The concept of independent shareholders is that the running of the business should be left in the hands of the board and the management team. However, SOCs are routinely subject to directions — implicit or tacit — by governments. As the Energy Reform Implementation Group (ERIG 2007, p. 8) — appointed by COAG to provide advice on energy sector reform — commented, 'political factors' appear to play a prominent role for government shareholders.

Some recent examples of directions include:

- a directive by the Queensland shareholding ministers that Energex not recover the 2011-12 increases in revenue arising from the Australian Competition Tribunal's determination on 19 May 2011, or of the costs of the 2010-11 floods
- as noted above, directions by the NSW Government in relation to its procurement plan
- in 2009, the Tasmanian Government wrote to Aurora Energy to express 'a desire' for tariff increases charged under the Aurora Energy Pay as You Go (APAYG) billing system to be capped for concession cardholders at a rate below that at which Aurora Energy was intending to charge (Electricity Supply Industry Expert Panel 2012a, p. 61).

These directives reduced the income flows of the businesses to their shareholders. No private shareholder would contemplate this unless there were compelling, well-articulated reasons why it would raise long-term shareholder value.

Moreover, as noted earlier, governments can affect the capital spending of the businesses by changing reliability standards, or (as has happened in the past) constrain expenditure through a government austerity or debt reduction program. Recently, these businesses have spent more than their forecast expenditure, while in the more distant past, some state-owned network companies appear to have spent less than desirable. Cycles of underspending followed by reliability problems and then periods of overspending are not consistent with efficiently providing network services in the long-term interests of consumers, and appear to reflect political, rather than economic considerations.

[10] Based on various annual reports and plans issued by the businesses (SP AusNet 2011; CitiPower, 2011; Ausgrid 2011a; Jemena 2011; Endeavour Energy 2011).

Governance structures

Quite aside from the various constraints posed by regulations and ministerial directions, the governance arrangements of state-owned network businesses are sometimes flawed. In particular, not all state-owned network businesses are subject to the Corporations Act or merit-based board appointments.

The Corporations Act 2001 sets out the laws dealing with commercial business entities in Australia. It regulates such matters as the formation and operation of companies and appointment of company directors. However, not all state-owned businesses are subject to the Act (for example, Ausgrid).

Moreover, in New South Wales, the *Energy Services Corporations Act 1995* provides that an 'energy services corporation' (which includes network businesses) is to have a board of directors that includes a Unions NSW nominee.[11] The voting shareholders appoint the Unions NSW nominee on the recommendation of a selection committee comprising representatives of the portfolio minister and Unions NSW. Regardless of whether, in fact, the person selected is of high calibre, this process conflicts with open merit-based appointments, which are central aspect of the good governance of commercial enterprises (an observation also made by IPART 2010, p. 79).

Moreover, industrial relations matters, such as outsourcing policy, are a central concern for management and the presence of a compulsorily appointed union-based director creates a perceived, if not actual conflict of interest. (The Commission understands that the New South Wales Government intends to remove the union appointment provisions from the Energy Services Corporations Act 1995.)

7.4 The productivity and performance of state-owned businesses

While analysis of relative efficiency is difficult, the empirical evidence suggests that as a group, the aggregate productivity outcomes of the state-owned network businesses are poorer that their private peers. While the main evidence is reported in chapter 6, it is useful to consider some more qualitative indicators.

On the positive side, poor overall outcomes does not mean poor performance on all counts or for all businesses. For example, IPART (2010, p. 48) noted that TransGrid, the New South Wales state-owned transmission business, was in the

[11] New South Wales is an exception, with Queensland and Tasmania requiring merit-based appointments.

'leader' quadrant in the International Transmission Operations and Maintenance Study (ITOMS), with low cost and high service performance. IPART was more cautious in its judgments on the performance of the distribution businesses in NSW, reaching the conclusion that on some limited benchmarks, the operating costs of the NSW DNSPs appear 'comparable' with their peers.

On the other hand, IPART saw considerable room for the improvement of all state-owned corporations in NSW, including the network businesses. The main focus for policy reform was the removal of some of the constraints on their performance resulting from their ownership, and in particular a need for more effective shareholder monitoring (IPART 2010, p. 13). IPART sought feedback from the businesses themselves, and while it is not clear to what extent these concerns applied to electricity network businesses, some pointed out that:

- some inefficient work practices were deeply entrenched (IPART 2010, p. 67)
- there were government constraints and interventions on hiring and firing (including a 'no forced redundancies' policy), and on out-sourcing and in-sourcing, and the conditions and types of employment offered. (The apparent processes for outsourcing for Ausgrid appear to be laborious — box 7.2).

When combined with the evidence in chapter 6, it seems likely that significant changes to governance or privatisation would lift the performance of the NSW businesses.

In Tasmania, the most recent review considered that the state-owned businesses had underperformed, citing consistent overspending (Electricity Supply Industry Expert Panel 2012a, p. 203):

> The apparent willingness of the regulated businesses to regularly overspend regulatory allowances and the preparedness by Boards and the Shareholders to accept the financial consequences of this through poor financial performance and lower returns to the Budget has created an environment where there is not a consistent focus on driving business performance.

In the Commission's discussions with participants, several highlighted that the businesses had an historical engineering focus on building things — if 'in doubt make it stout', or as EnerNOC (sub. 7, p. 3) characterised it: 'capex good, opex bad'. Some claimed that this attitude had persisted to a greater degree in the corporatised state-owned enterprises. Again this would lower efficiency.

Box 7.2 The Ausgrid Agreement: Outsourcing

7.1 In circumstances where Ausgrid is examining outsourcing or contracting out of work activities:

7.1.1 It will advise the employees and their union(s) and provide them with at least 28 days' notice to respond with suitable proposals about possible alternative arrangements to outsourcing or contracting out;

7.1.2 Prior to expressions of interest or tenders being called, where employee generated alternatives are received, such alternatives will be considered;

7.1.3 If it is subsequently determined that expressions of interest or tenders are to be invited, Ausgrid will provide the union(s) with a copy of the document which has been prepared.

7.1.4 Expressions of interest or tenders when advertised shall be timed so as to provide the employees with an opportunity to submit a conforming expression of interest or tender to do the work to an equivalent standard, timetable and price.

7.1.5 If an employee generated conforming expression of interest or tender is submitted, it shall be evaluated together with external submissions received.

7.2 Work will only be outsourced or contracted out when it can be demonstrated that either;

7.2.1 insufficient overall resources are available to meet the current Ausgrid overall work commitment and work timetable, or

7.2.2 the failure to complete the work in a reasonable time would jeopardise the safety of the public or impact adversely upon system performance, or

7.2.3 the use of outsourcing or contracting out the work is commercially the most advantageous option taking into account quality, safety, performance, cost and the overall strategic direction of Ausgrid.

7.3 When a decision is made by Ausgrid to outsource/contract out work not already outsourced or contracted out, or in a review of existing contracts, Ausgrid will only award a contract to a contractor that demonstrates it has established appropriate industrial relations policies and practices and that it complies with industry safety standards, environmental standards and quality standards.

7.4 In evaluation of conforming expressions of interest or tenders, any comparisons will be made on a basis discounting any overheads that would continue even if the work was outsourced or contracted out. Such overheads would typically include tendering costs, contact administration, contract supervision and the cost of any redundancies which may arise as a result of the decision to outsource or contract out.

7.5 In the event that it is determined to outsource or contract out work, affected employees will have access to the full range of options available under the Ausgrid policies which apply at the time, including training and/or retraining.

Source: Ausgrid (2010a).

What does the international literature suggest?

Only a few studies have examined the privatisation of network businesses alone — and these have consistently shown improvements in performance.[12]

However, our preliminary reading of the remaining literature on privatisation is that it mostly does not control for other coincident events, which confuse estimates of the impacts of privatisation of network businesses with other changes. In many instances, privatisation was associated with broader liberalisation of the electricity sector, particularly changes in regulatory arrangements and vertical separation of generation and retailing from network provision (Pollitt 2012 in a wide-ranging meta study).

As an example, in the UK, Crouch (2006) concluded:

> This system has worked well since privatisation. Costs have fallen significantly, distribution charges to domestic customers have reduced by 50% in real terms and companies have broadly delivered the requirements that have been placed on them to the benefit of consumers, including improvements in the quality and security of supply.

However, much of this gain would have reflected the joint implementation of CPI-x regulation and privatisation. Jamasb and Pollitt echo this conclusion, arguing that 'when accompanied by effective regulation, privatisation has achieved efficiency improvements' (2007a, p. 6164). This is certainly consistent with the empirical evidence for Australia.

The bottom line

The rationale for state ownership of network businesses no longer holds. State-owned status is ill-suited to the current incentive regulatory regime. State-owned network businesses appear to be less efficient than their private sector peers. This is not surprising given their multiple objectives, political intervention and the imposition of non-commercial restrictions.

Privatisation is not a radical move. As it is accompanied by regulation, it does not allow the businesses to exploit their market power or to lower reliability. There have been few problems in Victoria or South Australia. (Moreover, privatisation of generators and retailers also do not seem to have produced adverse outcomes.)

[12] Söderberg (2011); Anaya (2010); and Bradbury and Hooks (2008); and as summarised by Pollitt (2012) — Galal et al. (1994); Domah and Pollitt (2001); Toba (2002); and Mota (2003).

There are compelling grounds for privatisation of all electricity network businesses in the National Electricity Market.

DRAFT RECOMMENDATION 7.1

State and territory governments should privatise their state-owned network businesses.

DRAFT RECOMMENDATION 7.2

If state and territory governments do not implement draft recommendation 7.1, then they should promote more efficient outcomes for their state-owned network businesses by ensuring that:

- ***directors are appointed on merit, following a transparent selection process***
- ***ministerial directions are publicly disclosed at the time they are made and disclosed in the annual report***
- ***directors and officers are subject to the obligations under the Corporations Act***
- ***governments review objectives currently given to network businesses and:***
  - ***remove those that would be more appropriately allocated to other agencies***
  - ***remove those that are non–commercial and make it clear that the board is expected to deliver a dividend payout and rate of return on the equity invested in the network business that would be considered acceptable by an independent investor***
  - ***where conflicting objectives remain, provide publicly transparent guidance on how to prioritise them.***

8 How should the Australian Energy Regulator use benchmarking?

Key points

- At this stage, aggregate benchmarking models are ill suited to setting regulatory revenue allowances. However, benchmarking:
  - is a useful diagnostic tool that can help assess the reasonableness of bottoms-up proposals. More elaborate benchmarking should act as a discipline on proposals by network business and should be implemented as soon as possible
  - may facilitate negotiated arrangements that bypass the current costly and protracted regulatory processes. This 'short circuit' approach should only apply where the benchmarking models suggest that costs are reasonable
  - can provide information to consumers and others that provides pressure for improved performance by network businesses.
- Over the longer run, there may be scope for a larger role for benchmarking in determining regulatory allowances, but this should be subject to:
  - demonstration that the results are robust
  - the requirement that the Australian Energy Regulator (AER) does not choose the 'frontier' firm as the benchmark, but a yardstick more akin to that applying in competitive markets — which would be a firm close to, but not at the frontier.
- The AER will need to adopt various processes to ensure the successful use and evolution of benchmarking, including:
  - the development of publicly available databases and full transparency in its processes and methods
  - the development and retention of internal expertise
  - strategies that maximise learning
  - international collaboration
  - peer review of its benchmarking practices ('benchmarking of benchmarking')
  - appropriate consultation with stakeholders about the required data and appropriate methods
  - effective communication of the results of benchmarking to its diverse audiences
  - regular checking to ensure that the benefits of its benchmarking practices exceed the compliance and resource burdens.

A major international survey ranked Australia as a relatively unsophisticated user of benchmarking in electricity networks (Haney and Pollitt 2011). End users have also criticised the limited use of benchmarking in the current regulatory regime:

> Our view is that benchmarking has generally had an insignificant role in the AER's determination of expenditure allowances. We have observed that in most of its determinations there is no evidence that the AER has benchmarked capitalised expenditure allowances at all. The benchmarking that it has done of operating expenditures has not, in our opinion, been adequate. Even where there is some evidence of benchmarking by the AER, there is no evidence of how this information affected its view of the appropriate expenditure allowances. (EUAA, sub. 24, p. 4)

> The AER has not used benchmarking effectively and yes it should adopt different practices. The reasons for this probably lie with the regulatory approach (propose/respond) the AER must implement. (MEU, sub. 11, p. 30)

This raises the question of the appropriate aspirations for benchmarking in an Australian context — recognising the limits raised in chapter 4. The type of benchmarking and the manner of its application will depend on the purposes of its use — the policy imperative is 'do not use benchmarking on its own account'. There are many such purposes, with implications for the degree to which the tests set out in chapter 4 would need to be met.

This chapter examines the different ways that the AER could use benchmarking to achieve better outcomes. Some of these uses are alternatives, but some are complementary.

- Section 8.1 considers whether the AER could use benchmarking as the primary basis for its revenue determinations, and highlights some of the major drawbacks in that approach at this stage.
- Section 8.2 examines the degree to which higher-level benchmarking could indicate the overall effectiveness of the regulatory regime, which would have implications for policy settings, as well as provide a guide to whether the regime is achieving its intended purposes.
- The current bottoms-up approach in determining revenue allowances is exhaustive in its detail — one of the reasons for the increasingly lengthy documents used in the propose-respond model. The AER might use benchmarking to determine the areas where detailed analysis is required, while avoiding excessive analysis in other areas — in effect a filter for more targeted analysis (section 8.3).
- Currently, end-users (whether households or commercial users) are disenfranchised from the regulatory process. While greater engagement should occur whatever the form of the regulatory model (chapter 21), it may be possible for end-users to play an active model in reaching negotiated settlements in

regulatory determinations — avoiding the complex and protracted processes currently in place. Benchmarking would support such a framework (section 8.4).

- Benchmarking need not always directly inform regulatory decisions. In some cases, the publication of benchmarking results may create pressures for improved performance (section 8.5).
- While this chapter is sceptical of the degree to which benchmarking could play a major role in determining regulatory allowances in the near future, that may change over the longer-term with the increasing sophistication of the models and with better data. In that instance, benchmarking could assume a more prominent role (section 8.6).

Regardless of the particular purposes of benchmarking, the regulator has to develop competencies in benchmarking and follow processes that ensure that others can interpret and use the results, and that compliance and other cost associated with benchmarking are moderated. Section 8.7 spells out the processes that will achieve cost effective and useful benchmarking.

8.1 Could benchmarking have a mechanistic role in setting revenue allowances?

The apparently greater simplicity and clarity of using aggregate benchmarking as the primary basis for setting revenue allowances lies behind its attraction for some parties.

Setting aggregate capex and opex in building block models

A regulator (or indeed a business proponent) could use aggregate benchmarking to *determine* measures of total efficient forecast operating expenditure (opex) and capital expenditure (capex), which would then be included as the key inputs of the standard building blocks model.[1] (The weighted average cost of capital — WACC — would be estimated in the way described in chapter 5.) This would represent a significant departure from the current common practice of deriving the total cost forecasts used in the building blocks model by aggregating many detailed sub-

[1] The term 'building blocks' refers to a relatively simple procedure for determining the total revenue allowance, based on total capex, opex, depreciation, and the weighted average cost (chapter 5). The building blocks model can be either simple or complex, depending on how its inputs are estimated. In that sense, benchmarking is not inconsistent with the use of a building blocks approach (ETSA Utilities et al, sub. 6, p. 10).

components of total spending (as described by Major Energy Users, sub. 11, p. 10), with benchmarking at best informing that process.

Setting revenues based on CPI-x

A second mechanistic approach is to use the CPI-x approach (as described in chapter 4) for the forthcoming regulatory period, with x based on the total factor productivity growth estimates. This would not require a building blocks approach at all, since it would focus at the highest possible level of aggregation. In its submission to the Commission, the Australian Energy Market Commission (AEMC) commented:

> Alternatively, a TFP [total factor productivity] methodology could be applied in a more mechanistic manner where TFP indices are used to set the allowed rate of change of allowed revenues over the regulatory period. This methodology would be applied as an alternative to the existing building block approach established in the Rules. (AEMC, sub. 16, p. 1)

A 'supra- aggregate' benchmarking model

A third, more ambitious approach would use 'supra-aggregate' benchmarking at the commencement of any regulatory period to set the required total revenue allowance, without any reference to the role of the WACC, capex and opex, or the historical costs of the business (with the absence of the latter being the contrast to the CPI-x approach above). The business would then make all the choices about how to provide the services, including between capex and opex. This would be akin to the kind of benchmarking analysis used by Mountain (2011) and Mountain and Littlechild (2010), in that the benchmarking model would estimate revenue per customer.

The regulator would not need to formally roll any capital into a regulated asset base (RAB) in the next period, but would need to ensure that the benchmark method used related to the long-run marginal costs of supplying services. If the regulator took a long-run perspective, then it would have little incentive to ex post under-remunerate the sunk investments of the businesses ('asset stranding'). (The National Electricity Objective's long-term focus would oblige the AER to do this.) On the face of it, this would be a simple scheme, although in reality, the story is different.

Problems with deterministic approaches

While apparently more simple than current approaches, all of these approaches have major theoretical and practical difficulties:

In respect of the CPI-x method, the AEMC did not believe that data was yet adequate, but that it could work as an alternative mechanism for setting allowances in the future. If the basis for x was productivity within the network industry, the wave of prospective mergers in New South Wales (and uncertainties about future structural change in the industry) combined with slowly developing data collection, means that even that aspiration seems optimistic over the medium term. Chapter 4 also noted that a 'pure' CPI-x approach could preserve inefficiency or perpetuate rents.

It is also not clear how regulators would derive x in practice. Comprehensive reviews by Farrier Swier Consulting (2002), the AEMC (2011b) and London Economics (2008) found a wide range of methods used by regulators to actually set x. These include assuming a value of x;[2] setting it as a catch-up factor to move businesses from a level of inefficiency to better performance over several years; using it to freeze prices (x=CPI); basing it on business proposals; and (most rigorously) determining it using technical analysis. Many of these are pragmatic rather than scientific choices. However, so long as x is not too high,[3] and adjustments to initial revenues are not too dramatic,[4] CPI-x approaches provide strong incentives for productivity, while ensuring business viability and placing a (arbitrary) floor on network price changes for consumers. So a reasonable operational rule would be to set an x sufficiently low that it gives the business some scope to keep some of the gains of higher productivity growth. Preliminary ongoing development of TFP indexes would still be useful, if nothing else to assess the degree to which they become more reliable. Nevertheless, as the AEMC, notes, its practical realisation is some way off.

Similar — if not greater problems — would beset any deterministic use of benchmarking models reliant on cross-sectional data.[5] Their use would require

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2 For example, while Ofgem is often seen as one of the most prominent users of the CPI-x approach, the AEMC (2011b, p. 45) notes that x is based on a productivity growth 'assumption'.

3 An x above the industry-wide achievable productivity growth rate would not provide enough revenue *over time* for the business to fund efficient opex and capex.

4 Too dramatic a cut in revenue for any given business in the first year of a CPI-x regime would expose the business to immediate insolvency.

5 While methods that jointly use cross-sectional and time series (panel) data would help, given their better capacity to control for different operating environments, there has not been widespread testing of their reliability (Frontier Economics 2010b, p. 59).

strong confidence in the results, which would be misplaced given the findings in chapter 4. The deterministic approach has five other significant risks (to which the 'supra' aggregate approach would be particularly susceptible).

(a) Regulatory opportunism

Were electricity prices to be rising rapidly, there could be pressure on the regulator to choose tougher benchmarks (recognising that even were sophisticated benchmarking models to develop over time, it is likely that they could be tweaked to give higher or lower benchmarks)

As explained by Yarrow (2012), the assumption of regulatory impartiality may not hold given opportunism:

> By way of further example of the difficulties with the arguments as they presently stand, consider the argument that the current 'propose-respond' process precludes the AER from substituting 'impartial' forecasts of costs for what are claimed to be the biased forecasts of costs that are submitted by the companies. This argument begs a fundamental question. As discussed above, the working presumption in the relevant economics is that a regulator with unconstrained discretion to set price controls will be tempted to opportunism, and that the temptation will be particularly great in circumstances of rate-shock. That is, at bottom, there is an underinvestment problem associated with the regulation of private monopoly. (Yarrow 2012, p. 9)

The extent of regulatory risk perceived by the industry would depend partly on the specific characteristics of the AER itself, including its objectivity; its independence; its abilities and funding; and its general reputation in the industry (a matter discussed further in chapter 21).

(b) Future network developments present a challenge for benchmark models

Unlike some investments where, once made, the additional investment requirements are modest (say a toll road), electricity networks require significant ongoing maintenance, replacement, new connections and other augmentation. Many network costs reflect expectations about the future characteristics of demand and supply, and these can change over time given the effect of climatic variations and peak loads. As such, many costs would be hard to incorporate into ex ante aggregate benchmark models (at least without significant further development). There would need to be a process for approving contingent projects.

(c) Benchmarking, information and efficient contracting

The AER's revenue allowance determinations are effectively contracts over the regulatory period between network businesses and the regulator, which acts on behalf of end users. Ultimately, among other factors, good contracts depend on both (i) shared and (ii) rich information about the nature of costs and contingencies.

There is a theoretical case that, where the regulatory regime allows businesses to exploit their information advantages over the regulator, restricting the relevant information for making a regulatory determination to a small set of variables (the only requirements for aggregate benchmarking) may produce better outcomes. That meets condition (i).

It would also meet (ii) if the selected class of variables adequately reflected the key operational differences of the businesses concerned. But few participants in this inquiry suggested this was currently possible. In that case, rather than forcing both regulators and businesses to act as nescient players in their dealings with each other, a preferred approach would be to:

- correct the flaws in the incentive arrangements (using the approaches set out in chapter 5) that allow businesses an excessive capacity to exploit their informational advantages
- ensure adequate provision of relevant detailed information (and not rely on the exclusive use of aggregate benchmarking).

Reliance on too lean an information set would increase regulatory risk and require the regulator to pay a premium to cover that risk. There would then be a trade-off between simplicity and cost.

(d) Detailed analysis would creep in via the back door

The checks and balances required to ensure aggregate benchmarking was reliable as the sole basis for setting revenue allowances would re-create the need for scrutiny of bottoms-up data to test the results (thus losing simplicity after all). At the very least, benchmarking models would need to address capex, opex and the WACC separately (thus reinstating the RAB as an important facet of the regulatory arrangements).

(e) Uncertainties about the merit review process

Moreover, it is not clear how merit review would proceed if regulators used aggregate benchmarking to determine revenue allowances. The outcomes would

depend on how merit review arrangements were structured (an issue currently before the Standing Council on Energy and Resources), but it is likely that decisions would involve:

- battles between econometricians.[6] That would have some advantages to the extent that it encouraged good statistical processes, clear statements of how to interpret the results, better data collection, and the development of expertise (as set out in figure 4.7 in chapter 4). However, given the data and modelling problems afflicting benchmarking, it is doubtful that a merits review body could reach a well-based judgment on whether it is meaningfully possible to, say, disentangle 'the heterogeneity from inefficiency in one step, using a latent class model for stochastic frontiers' (Cullmann 2009). A tribunal might then seek its own expert advice, but then the battle would be widened, but not necessarily won
- the re-admission of detailed data as the corroborating evidence on which to base the determination. The bottoms-up approach might then simply be deferred to the 'courtroom'. It is notable that in an appeal brought by Energy Australia, the Tribunal emphasised the relevance of the business's detailed information:

> EnergyAustralia is correct to submit that it is not the AER's role to simply make a decision it considers best. It is also correct for it to say that the AER should be very slow to reject a DNSP's proposal backed by detailed, relevant independent expert advice because the AER, on an uninformed basis, takes a different view. Nor, as EA submits, may the AER reject such a proposal merely because it has an expert opinion. The AER, based upon any expert advice, needs to make its own evaluation, an evaluation that is reviewable by this Tribunal. (Australian Competition Tribunal 2009, p. 56)

Currently, the arguments for the AER to use benchmarking to set allowances mechanistically are not compelling. The AER and the network businesses (and others) share this view (box 8.1).

8.2 Benchmarking could act as a basic test of the effectiveness of the regulatory regime

The AER and user groups have claimed that the existing regulatory arrangements have produced inefficient outcomes. This has been more informed by consideration of the incentive arrangements than by empirical analysis by the regulator (though some others have undertaken research — chapter 6).

6 With the inherent problems spelt out in detail by Rubinfeld (1985).

Box 8.1 Participants said benchmarking should not be used deterministically

The AER highlighted concerns about using benchmarking in a determinative fashion:

> Benchmarking is not a substitute for rigorous analysis and the exercise of judgement to determine expenditure allowances for a network business and cannot be used in a mechanistic fashion to directly determine expenditure allowances. However, when benchmarking is used prudently and carefully, and based on a robust specification that incorporates good quality data, it can be a very useful tool in the overall assessment of an expenditure proposal. (AER, sub. 13, p. 13)

> The AER considers that at the current time it cannot establish revenue allowances based primarily on the outcome of comparative benchmarking against other firms. When more standardised and appropriate data becomes available as a result of the application of the AER's new framework, noted above, and benchmarking models give more consistent results, the weighting given to top down benchmarking as a part of the AER's comparative analysis will likely increase. (AER 2010b, Appendices, p. 99)

A review of the international use of benchmarking in regulatory agencies worldwide indicated the dangers of using benchmarking to punish/reward businesses:

> The significant uncertainties in efficiency estimates could have important undesired consequences especially because in many cases the estimated efficiency scores are directly used to reward/punish individual companies through regulation schemes such as price-cap formulas. (Farsi et al. 2007, p. 13)

The network businesses themselves were (unsurprisingly) hostile to benchmarking as a determinative tool:

> The ENA considers that it is not yet possible to set efficient costs using pure statistical benchmarking at high levels of aggregation without regard to expert interpretation. Doing so would impose material regulatory risk on the businesses and deter much needed investment in the regulated network sector (ENA, sub. 17, p. 5)

> The Businesses are not aware of any country that uses benchmarking exclusively to regulate DNSPs' revenues and prices. (ETSA Utilities et al., sub. 6, p. 30)

> Perhaps more importantly, high level aggregate benchmarking with the use of a few high level causal factors makes it impossible to 'sanity check' the results that come out of a statistical model with the real world engineering constraints facing a business. If the regulator determines that expenditure on zone substation is not efficient because less costly alternatives exist, then this is a finding that can be contested on the available facts. By contrast, consider an example where a regulator decides that five per cent of total expenditure is not efficient purely on the basis of a high level statistical comparison to other businesses. This reasoning provides no indication of what aspects of the expenditure proposal are imprudent. Consequently, the business has no recourse to defend its proposed asset investment program on the engineering needs of the business because this was not the basis of the regulator's finding. (ENA, sub. 17, p. 27)

Others have been similarly cautious:

> The CEC agrees with the Commission that benchmarking will be unable to supersede the current 'building block' approach taken by the AER. Rather, benchmarking methods should be able to be applied by the AER in order to provide supporting information to its determinations. Indeed, benchmarking should be another tool from the AER's toolbox of revenue assessment tools at its disposal. Given the broad use of benchmarking in regulated markets globally the CEC sees no reason why this could not be the case. (Clean Energy Council, sub. 38, p. 3)

Upper level benchmarking should at least provide further information about the effectiveness of the regulatory regime (even if it is changed following the recent Rule change request by the AER).

As well as cross-sectional benchmarking (as described in chapter 4), the AER should also model growth rates of total factor productivity (and their constituent partial productivity rates) — for each business and for the industry as a whole. This would highlight how any business is performing compared with the entire electricity network and with other industries in the Australian economy. This would also test the degree to which revenue determinations reflected ongoing negative (or low) TFP growth (and would assist in any progression to CPI-x benchmarking later).[7]

Any such indicative aggregated benchmarking analysis should control for the most important differences in the operating environments of businesses — such as customer density, line type and length, reliability requirements, and the capital vintage of relevant assets.

DRAFT RECOMMENDATION 8.1

The Australian Energy Regulator should regularly undertake aggregate benchmarking of the performance of network businesses, including of their:

- ***multifactor productivity — the output of services for given inputs***
- ***separate productivity of capital, labour and intermediate inputs.***

The results should control, to the best extent available, for any significant variations in the operating environments of the businesses, including customer density, line type and length, reliability requirements, and the capital vintage of relevant assets.

As emphasised in chapters 1 and 4, rigorous benchmarking analysis may highlight the efficiency impacts of the regulatory and policy environments facing network businesses. While most of the regulator's interest in benchmarking is on the *residuals* from a model (the proxies for the inefficiency levels of businesses), policymakers should concentrate on the estimated *parameters* regarding policy variables in any model. In the current imperfect policy environment, those parameters may reveal the most lucrative direction for reform. These policy opportunities are the principal subjects of chapters 9 to 16.

7 The AEMC (2011b) proposed a similar approach to pre-testing of TFP methods. In its review of TFP benchmarking, it recommended 'paper trials' of benchmarking before considering further Rule changes in the area.

8.3 Could more targeted analysis act as a filter?

Benchmarking could be used as a diagnostic tool to identify areas of a proposal that may require greater scrutiny, but without it assuming a determinative role. Many participants supported the use of benchmarking as an input into the regulatory process (box 8.2).

Box 8.2 Benchmarking is a useful adjunct to other modelling

Many participants accepted the value of benchmarking as one input into the regulator's determination of the appropriate aggregate or disaggregated costs of the regulated business:

> The Businesses support the Rules' requirement for the AER to use benchmarking as part of the building block approach to test the efficiency of DNSPs' expenditure — and to choose which types of benchmarking techniques it will use — although this should recognise the inherent limitations of different benchmarking techniques and of the comparability of data. (ETSA Utilities et al., sub. 6, p. 15)

> Overall, benchmarking of certain performance outcomes is useful only as an adjunct to the establishment of revenues using the existing cost build-up approach. The fundamental objective enshrined in the National Electricity Law will not be achieved with regulatory uncertainty, which will ultimately deter investment. (APA Group, sub. 2, p. 2)

> Ergon Energy believes that benchmarking techniques are not robust enough to replace a detailed investigation of costs and should not be relied on entirely to set revenue allowances. Instead, benchmarking should be one of many assessment techniques adopted by the AER to determine efficient and prudent expenditure. (Ergon Energy, sub. 8, p. 9)

> In the ENA's view, pure statistical analysis is most likely to be useful: as a means of identifying anomalies in an expenditure proposal that require closer more detailed examination; or when applied at low levels of expenditure aggregation. (ENA, sub. 17, p. 5)

> … benchmarking results can also be used to allow the regulator to request further information. Consumer Action believes an appropriate first step to sophisticated benchmarking approaches should be to ensure that the regulator has more information combined with the ability to request further information/evidence from network businesses that under-perform. The onus should then be on the network businesses to justify and prove their case (in relation to revenue proposals). (Consumer Action Law Centre, sub. 5, p. 2)

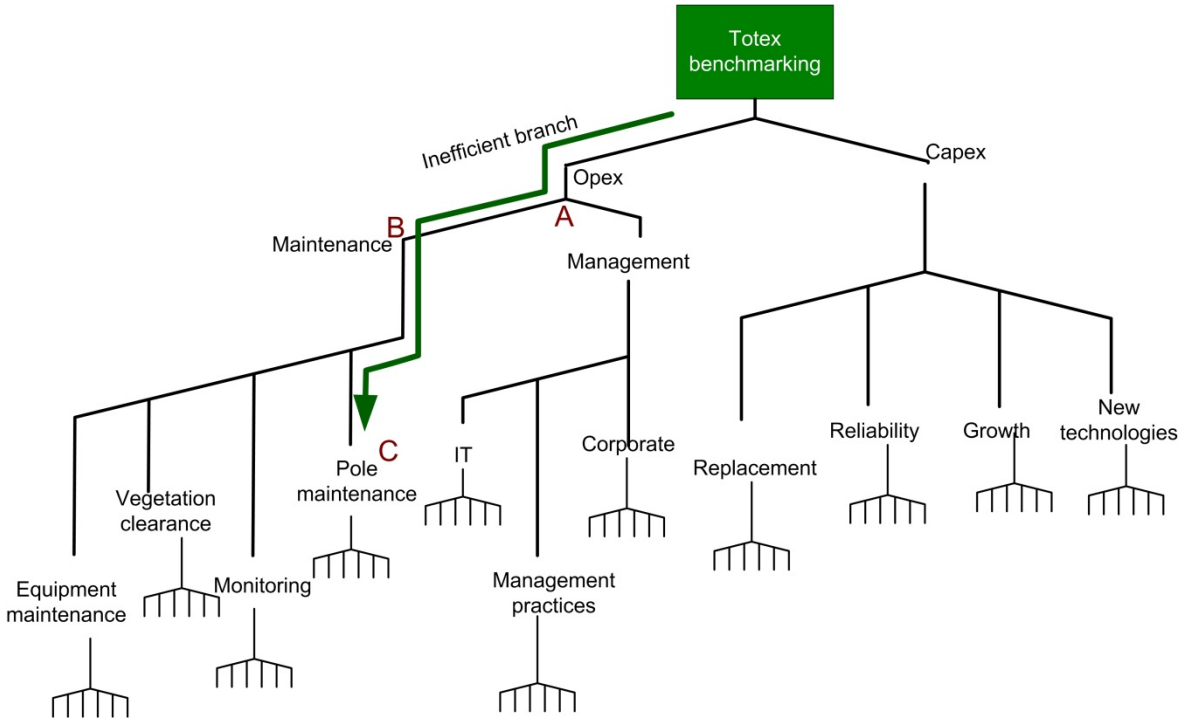
Some leading experts are pessimistic about the usefulness of benchmarking in economic regulation:

> In practice, benchmarking has proven either troublesome or irrelevant to the regulatory process, but proponents continue to search for 'better' models that will be more useful. … I conclude that, at best, benchmarking can help to focus regulatory enquiries, but that it shows no prospect of becoming a substitute for detailed evaluation of each regulated utility's own costs. (Shuttleworth 2005)

In looking at arrangements for Swiss distribution businesses Farsi et al. (2005, p. 1) concluded that benchmarking analysis should be used to support rather than to determine regulatory decisions.

Such aggregate benchmarking has advantages over detailed bottoms-up approaches in that it would test the businesses likely to be most inefficient in their capex or opex. The analysis could then bore down into the detail, but only down the branch where benchmarking revealed that costs were sufficiently distant from the efficiency frontier.

Figure 8.1 **Boring down through successive layers of network costs**[a]



[a] The chart is illustrative of the process, but not intended to depict the cost structures of distribution network businesses.

Where an expenditure class appeared close to best practice, further investigation of its constituent elements — of the forensic kind currently undertaken — would be avoided (box 8.3). The AER's repex model for modelling replacement expenditure by distribution businesses exemplifies this approach:

> The calibrated repex model, among other things (e.g. significance of expenditure), was used as a guide to whether or not we considered a detailed review of a specific asset category should be undertaken. (Nuttall Consulting 2010a, p. 31)

Any such analysis would have to consider substitution possibilities between certain classes of spending, particularly opex and capex.[8]

8 For example, Aurora Energy (2012, p. 73) has indicated that it will increasingly decide whether to replace an asset when it has actually deteriorated (rather than basing replacement on asset ages, which was its past practice). This approach will reduce replacement investment, but would be likely to increase monitoring costs.

Box 8.3 **The bottoms-up approach — getting into the detail**

Locks and keys

In its regulatory proposal to the AER, Ergon Energy proposed an allowance for expenditure on 300 000 locks and keys. The AER asked its consultants, PB Associates to assess this claim. As a result of this, Ergon revised its budget for locks and keys and provided 'a business case' for this expenditure including an 'options analysis'. PB Associates then assessed this claim by examining the number of locks per kilometre of track, and the number of keys to be provided. At the end of its review, PB Associates concluded that the scope of works was transparent and the cost estimate was well supported and so it decided that the revised budget for locks and keys was prudent and efficient. The AER then concluded that Ergon Energy provided a 'well substantiated' forecast for its revised keys and locks program in its revised regulatory proposal and so it accepted Ergon's revised proposal. The lock and key budget was less than 0.2 per cent of the total allowed expenditure by Ergon during its regulatory period. (Mountain 2011, p. 55)

The average span lengths of insulated conductors

The [blacked out writing] also assumes an average span length of 50m for an insulated conductor. This assumed span length is actually 25 per cent greater than the actual average span length. The [blacked out] identifies that CitiPower has 191km of ABC and 4,703 spans. This works out as an average of 40.6m per span. The reason why the longer span assumption was used when actual span length information was available is not clear. (Nuttall Consulting 2010a, p. 296)

Special trees

As a result of discussions with the ESV, United Energy has revised down its resource requirement to one full time equivalent (FTE) to establish the 'habitat' tree register in the first year (2011), followed by 0.4 FTE in subsequent years to monitor and update the register, process questions and information requests, and provide on-going training to employees and vegetation contractors. (Nuttall Consulting 2010a, p. 357)

Pole treatment processes

Aurora submitted that the AER erred in comparing Aurora's historical pole lives to pole lives achieved by mainland distribution network service providers (DNSPs) because Aurora uses a different type of timber pole to mainland DNSPs. In its draft determination the AER considered that the treatment of Aurora's timber poles should result in similar lives to the untreated mainland timber poles despite Aurora using a different timber class to mainland DNSPs. Aurora submitted that the treatment process typically only impregnates the sapwood (outer layers) whilst the heartwood (inner core) remains untreated. Aurora submitted that although treatment may extend pole life, there is no engineering reason to expect that it would result in a pole with the same life as the poles used on the mainland. (AER 2012f, p. 60)

Regardless of whether the regulator used a formal hierarchical modelling approach, aggregate opex/capex benchmarking could test the overall reasonableness of any

bottoms-up approach. If the two are sufficiently discordant, the regulator could ask the business to investigate the likely source of the difference, such as important omitted control variables that affect the benchmarking model. This would again focus attention on major rather than minor cost drivers, and improve the quality of the benchmarking models.

If two similar network businesses have very different unit costs, then they should be able to explain the probable reasons and to quantify them. Some networks have already used this approach:

> Country Energy provided us with a comparison that had been undertaken with Ergon Energy's vegetation management expenditure. The comparison showed that Ergon Energy had a similar profile of vegetation density and that after allowing for differences in cycles and size, Country Energy's proposed expenditure was comparable to that incurred by Ergon Energy. (Wilson Cook and Co. 2008, p. 41)

Requesting feedback from businesses about why results might diverge would not require the business to *demonstrate* how the benchmark result was wrong (notwithstanding the views of one key participant — box 8.2). Until the methods and the data underpinning benchmarking are significantly improved, reversing the existing onus of proof in the Rules would increase business risk significantly (Lowry and Getachew 2009, p. 1325).

Regardless of whether it is used in the way described in figure 8.1, disaggregated benchmarking could more generally be used to judge detailed bottoms-up aspects of a business's proposal (an approach supported by the ENA, sub. 17, p. 5). For example, this might relate to:

- vegetation management
- the linkages between asset vintages and replacement rates by major class of assets (such as poles and distribution substations)
- maintenance efficiency, such as time and resources to correct certain faults
- the efficient monitoring of assets.

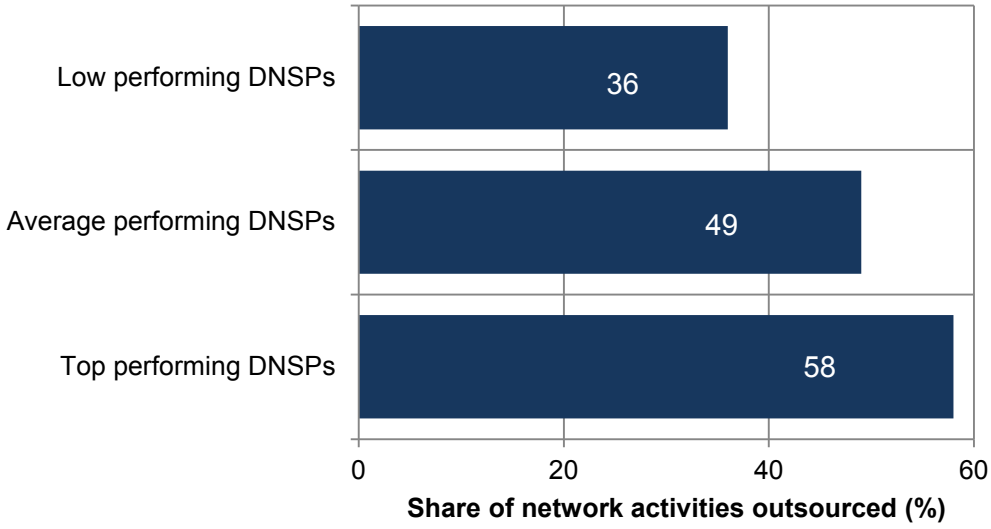
Such specific benchmarking may be reasonably reliable because there are fewer confounding variables.

Management performance measures should not be overlooked. For example, benchmarking of distribution businesses in Europe suggested that higher performing businesses were more likely to outsource their network functions (figure 8.2). Among other factors, management performance could be measured as the adoption rates of best-practice commercial processes and equipment, including:

- the use of customer panels and surveys (as these can be important elements of customer engagement)
- employment practices
- outsourcing (a way in which the business itself can exploit competitive processes)
- demand management (as a network alternative)
- information technologies (increasingly important as networks become 'smarter', and given the need to serve millions of customers and control complex networks efficiently)
- innovation
- financial controls
- procurement practices
- occupational safety
- project management.

Figure 8.2 **Do not overlook management processes**

Outsourcing and high performing firms in European distribution network businesses[a]



[a] Outsourced network activities related mainly to preventative maintenance, and assembly and construction.

Data source: Chanel, P. 2008, *Overview of Electricity, Distribution in Europe*, Summary from Capgemini's 2008 European benchmarking survey.

Following Turvey's advice (discussed in chapter 4), regulators need an 'understanding of what an enterprise does and how it does it' before collecting

information. Consequently, in determining relevant benchmarking performance and control variables, the Australian Energy Regulator should consult with network businesses, generators, retailers and network equipment suppliers.[9]

It is equally critical to test whether the performance measures are relevant to customers (by the type of customer). For example, customers may give different weights to connection costs, fault rectification times, reliability, and call centre performance, and may sometimes directly observe practices they regard as inefficient. Finally, and as emphasised later, electrical engineers and other experts may provide strong guidance on the most appropriate measures and controls, including the pitfalls in their measurement and interpretation.

DRAFT RECOMMENDATION 8.2

Subject to compliance and other costs (draft recommendation 8.12), the Australian Energy Regulator should accompany aggregate analysis with detailed benchmarking of particular aspects of the performance of the businesses, including:

- ***the rate of investment relative to the age-weighted capital stock by asset class***
- ***the efficiency of major maintenance activities***
- ***the adoption rate of best-practice commercial processes and equipment, including the use of customer panels and surveys, outsourcing, demand management, information technologies, financial controls, procurement practices, occupational safety, and project management.***

In determining relevant benchmarking performance and control variables, the Australian Energy Regulator should consult with:

- ***network businesses, generators, retailers and network equipment suppliers***
- ***customer representatives***
- ***relevant experts within Australia and internationally.***

As discussed in chapter 4, the small number of network businesses in Australia poses an obstacle to authoritative benchmarking, especially because it makes it hard to control for differences in operating environments. There are several strategies for addressing this:

- use combined time-series, cross-sectional (or panel) data
- collect data about different businesses' performances by feeder type, so that comparisons are more robust. For example, the AER (2008a, pp. 160ff)

9 This was recognised by the ACCC/AER (2012a, p. 166) and several participants in the inquiry, such as Ergon Energy (sub. 8, p. 10).

examined reliability by four feeder types — central business district, urban, short rural and long rural feeder

- collect data about the performance of different business units within businesses (for example, comparing in-house with contracted services, or monitoring activities in different areas).

Given that most people served by distribution networks are in Australia's major cities, comparisons between business performances within metropolitan areas are likely to be the most useful.

DRAFT RECOMMENDATION 8.3

The Australian Energy Regulator should periodically assess the comparative performance of network business units within particular sub-regions of the National Electricity Market, where:

- ***those sub-regions share similar physical operating environments***
- ***the costs and informational requirements of doing this are not too great (draft recommendation 8.12).***

The comparisons should relate to business units within a particular business, as well as comparable business units in different businesses.

The Australian Energy Regulator should place most emphasis on comparisons of the efficiency of distribution networks in different metropolitan areas.

Potential challenges of the targeted approach

This targeted approach may result in excessive rents for some businesses. Any benchmarking model will involve:

(i) false positives (firms that appear inefficient, but are not)

(ii) false negatives (firms that appear efficient, but are not).

Under the targeted approach, firms in (i) would be subject to more detailed scrutiny, which should correct the error, but businesses in (ii) would not. That would create an upward bias in revenue allowances. That may not matter greatly over successive determinations as the regulator learns more. Moreover, at least under (properly functioning) incentive regulation, businesses in (ii) have strong incentives to improve their performance. In that respect, the asymmetric treatment of false positives and negatives may be appropriate. However, were the negotiated approach outlined in section 8.4 to be used, it would also probably reduce the incidence (or

severity) of false positives, as customers would have some bargaining power to reduce rents.

A further challenge is that, notwithstanding its greater likely reliability and accuracy, the passage of disaggregated benchmarking through the limited merit review process still suggests that it can be problematic to control for the relevant differences in the operating environments of the businesses (box 8.4).

8.4 Benchmarking could be a trigger for negotiated settlements

As the analytical rigour of aggregate benchmarking develops, it could also encourage early settlement in determinations, short-circuiting the protracted, uncertain and costly processes currently applying under the Rules (figure 8.3). The current costs of the determination process are up to $15 million for each network firm and up to $6 million for the AER (AEMC 2009a, p. 9). In considering the advantages of CPI-x as a simpler approach to determinations, the AEMC (2011b, p. iii) estimated that the approximate cost of one complete cycle of revenue determinations using the current building blocks method was $330 million (of which the component paid by the businesses would mainly be passed onto consumers).

Under a 'short circuit' approach, depending on the divergence between benchmarking and the business proposal, the AER could immediately accept a proposal as reasonable, or if the proposal was in the 'ballpark', commence negotiations with the network business, with the involvement of customers. These would be better informed because of published benchmarking analyses, and could act better on this information given the reforms to their resourcing set out in chapter 21.

The AER could also request further information (a 'please explain' notice) to assist the early resolution of an agreement. Failing a quick resolution, the AER would adopt the current forensic and protracted processes, with the risks and costs that this would involve for all parties.

Box 8.4 **The fiery hoop of merits review**

CitiPower and Powercor each challenged the AER's expenditure allowances for vegetation clearance (with the Tribunal considering their concerns in a single review). The AER's ruling relied heavily on benchmarking the costs of Powercor and Citipower against those of other distribution networks. The challenge provides a useful case study of how the limited merits review has applied to benchmarking.

The network's proposal lacked explanatory evidence. The Tribunal agreed that it should not have been accepted. However, the AER also had to prove that its judgement was reasonable under the Rules. Similar boundaries are likely to apply to benchmarking in the future.

The Tribunal had agreed in principle with the AER's treatment of the proposal, given the lack of explanatory information.

> The AER was entitled to be suspicious of the quantum of the step change amounts claimed by each of CitiPower and Powercor given the shortcomings in the information provided and the significant increase over the 2009 base year. Furthermore, it was entitled to benchmark those rates against information provided by the other DNSPs.
>
> In our view, CitiPower and Powercor had ample opportunity to provide greater assurance to the AER concerning the step change amounts which they had claimed. They must be taken to have understood that the AER would wish to look at the rates which underpinned those amounts carefully, would wish to benchmark them against the other DNSPs' rates and would wish to cross-check them as against expenditure in prior periods. (Application by United Energy Distribution Pty Limited [2012] ACompT 1).

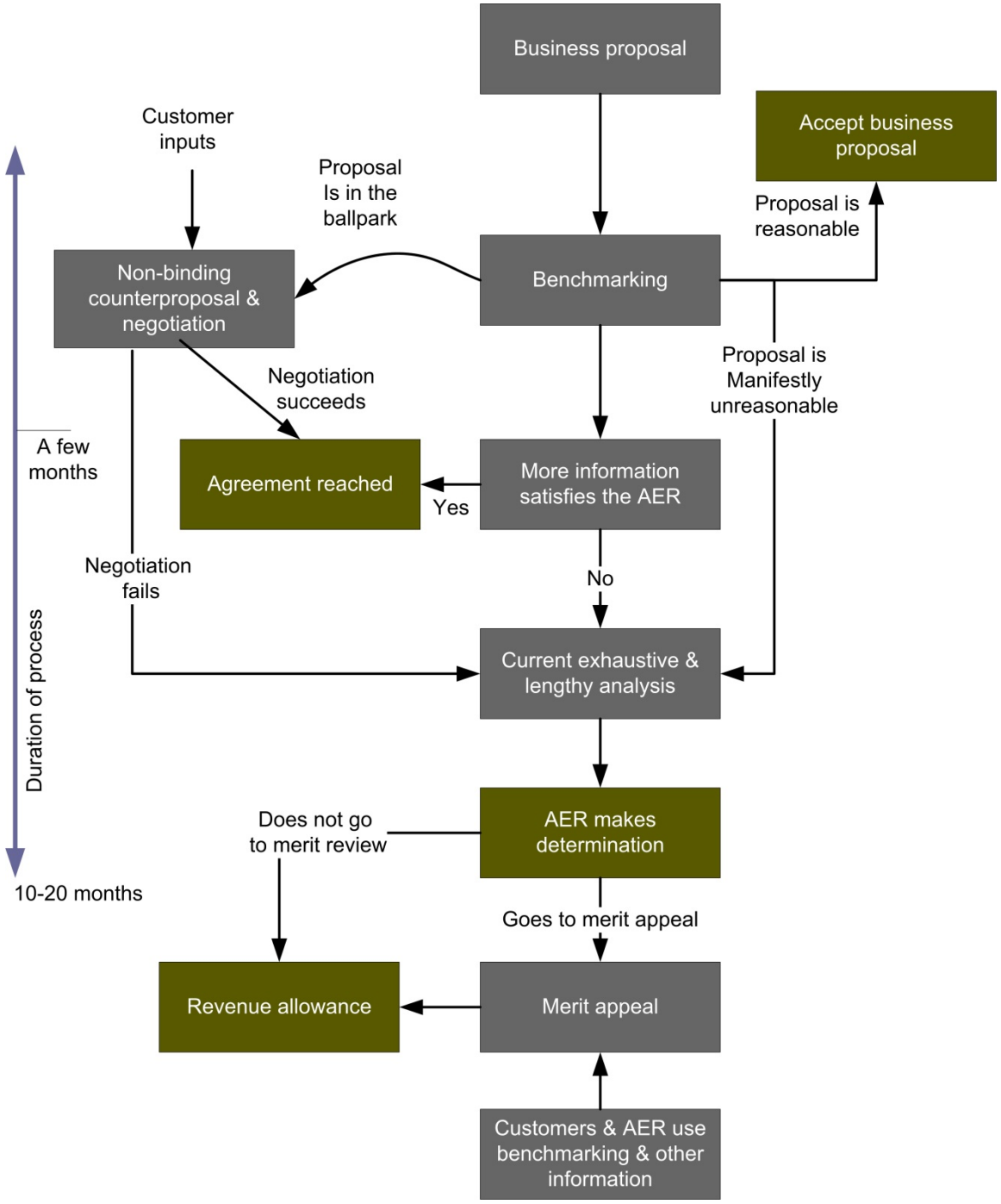
On the other hand, the Tribunal also considered the benchmarking undertaken by the AER, and found that it had not considered factors which were likely to be significant.

> … the assessment made by Nuttall Consulting failed to pay proper regard to the differences between Powercor's network and those of the other DNSPs and failed to take proper account of the differences between the work programs which had been put in place by Powercor, in particular, and those which the other DNSPs proposed to undertake. After all, the work programs which Powercor had put in place had been assessed as reasonable by ESV, at the behest of the AER. ESV had concluded that the Powercor work programs constituted a reasonable response to the new regulatory environment created by the Victorian Government as a result of the Black Saturday bushfires.
>
> The AER was justified in not being satisfied with the VEMCO costings [Vemco Pty Ltd is an independent, third party vegetation management contractor]. However, its assessment of the costs of Powercor's work programs was unreasonable. (ibid)

The Tribunal's decision was to remit the matter back to the AER.

The Rules suggest that if the AER were to use benchmarking as a tool for early settlement, it would still be obliged to consider a range of other evidence. A Rule change may be justified to allow the AER to use benchmarking (or any other evidence at its discretion) on a standalone basis where it led to an early and mutually agreed outcome with the business.

Figure 8.3 **Benchmarking as a short circuit**



An elaboration of this model would be to use benchmarking to empower customers in any merit review process. The EUAA cited an example where the availability of benchmarking might have assisted in the merit review process:

> The [Australian Competition Tribunal] refused the EUAA leave to appeal on the basis that the EUAA could not demonstrate that the AER's failure to have regard to benchmarks satisfied the financial threshold for appeals under the National Electricity

> Law. The Tribunal required the EUAA to have benchmarked the distributors' expenditure and to show that, had the AER also done this, the expenditure allowance would have been significantly lower than the allowance determined by the AER. Obviously, the EUAA was not in a position to undertake extensive regulatory benchmarking itself and so could not satisfy the Tribunal's criterion for leave to appeal the AER's determination. (EUAA, sub. 24, p. 4).

There are precedents for benchmarking as a short-circuit

In California, benchmarking analysis is used in the settlement process between the business and a consumer advocate:

> [The role of the DRA — the Division of Ratepayer Advocates] is to advocate on behalf of the customers of regulated public utilities. It represents consumers in the CPUC [California Public Utilities Commission] proceedings, including rate settings, investigations, and rule makings. The DRA also participates in CPUC-sponsored working groups, advisory boards, workshops, and other forums. The DRA also evaluates utility proposals, investigates issues, presents findings and formal testimony, litigates complaints, and makes recommendations to the CPUC and to other forums. The DRA must 'represent and advocate on behalf of the interests of public utility customers and subscribers…to obtain the lowest possible rate for service consistent with reliable and safe service levels'. The DRA also has statutory rights to obtain information from utilities through discovery and other means. The CPUC is required to provide sufficient legal support for the DRA, and provide the DRA with its own lead counsel. (ACCC/AER 2012b, p. 176)

Ofgem has proposed the implementation of a similar approach for the regulation of UK electricity networks. In the Ofgem Information Quality Incentive framework, firms are initially judged on the quality of their proposals; their past performance; and benchmarking exercises. Firms are then categorised accordingly as:

- requiring a low level of scrutiny — business plans would typically be given a shorter assessment, and final determinations would be relatively early
- requiring a moderate level of scrutiny — assessments would focus on the deficiencies of the proposal, as well as past performance. Capital projects may be subject to random inspections. Determinations would likely run their normal duration
- requiring a high level of scrutiny — business plans would be subject to a full engineering and economic analysis, as well as follow up analysis. Firms may be required to supplement their business plans with further explanatory data. Determinations would likely run their normal duration. (Ofgem 2010, p. 58)

Regulation of water in Italy has used a similar approach. The business proposes a tariff in the first step. The regulator estimates a price cap using benchmarking

analysis, and approves the business's proposal if it lies within an acceptable range around the estimated price cap. If it does not, then the tariff is renegotiated with the business required to justify its excessive tariff before any revision (Farsi et al. 2005, p. 25).

DRAFT RECOMMENDATION 8.4

The Rules should be changed to allow the Regulator to have the discretion to initiate a three-way negotiation of a mutually acceptable settlement, involving itself, the business, and a representative and qualified customer group similar, or identical, to that identified in draft recommendation 21.3.

- ***Negotiation would only be triggered if the Australian Energy Regulator judged that the divergence between aggregate benchmarking estimates of forecast spending and the business's proposal were sufficiently narrow.***
- ***Where an arrangement was successfully negotiated using this process, the Australian Energy Regulator should not be obliged to go through the current formal draft/final determination processes.***

8.5 Information and 'moral suasion'

Benchmarking at any level of aggregation could be used to inform customers (and media) about the relative performance of businesses, which provides indirect pressures on inefficient businesses and their shareholders (including state governments). In this respect, the Consumer Action Law Centre pointed out:

> Enhanced information and transparency about regulated network businesses can benefit the regulatory process as well as improving the behaviour of network businesses. A better-informed regulator will produce more efficient price setting, while comparative analysis and reporting on the network businesses' performance by the regulator can create an incentive for the network businesses to 'self-discipline' as a result of competition-by- comparison and brand protection. (sub. 5, p. 1)

Aside from contributing to determinations, the advantage of systematic benchmarking comparisons between network businesses at the micro and macro level is that it could identify groups of firms that are consistently more efficient, and highlight some of the potential causes of the efficiency gaps (an issue raised in chapter 4).

8.6 The long-run application of benchmarking

As discussed in section 8.1, there is little immediate scope for aggregate benchmarking to serve as a sound basis for the regulatory determination of revenue allowances. Nevertheless, there are longer-term prospects for more sophisticated benchmarking:

> The AER now has extensive information gathering powers under the NEL and it is exercising those powers. Over time, that should produce a data-set that could support more extensive use of benchmarking and the use of more sophisticated benchmarking techniques; however that is some way off. (Jemena, sub. 21, p. 10)

Subject to the development of improved data, reliable (and corroborated) models, and better-designed incentives arrangements, there may be greater scope to give more weight to aggregated benchmarking. Nevertheless, the risk of regulatory error would still persist. The protection against regulatory error would be to set the benchmark at a level close to the competitive market standard — such as the 75th percentile — rather than at the frontier (Newton et al. 2009, p. 1329). The Major Energy Users also recognised the need for the long-run viability of the network businesses when setting the benchmark:

> If it is awarded too little revenue which is based on the efficient frontier, then the firm could be in financial trouble which would be a worse outcome for consumers. (MEU, sub. 11, p. 26)

DRAFT RECOMMENDATION 8.5

In any of the next rounds of regulatory determinations, the Australian Energy Regulator should not use aggregate benchmarking as the exclusive basis for making a determination. Instead, the Australian Energy Regulator should use such aggregate benchmarking results as a diagnostic tool in responding to business cost forecasts.

However, if the processes proposed in draft recommendations 8.9 to 8.11 led to sufficiently robust benchmarking, then:

- ***a business would continue to make a detailed cost proposal, but if the overall proposal were divergent from the regulator's benchmarking estimate, the onus of proof would be for a network business to provide quantitative evidence demonstrating why its cost forecast was preferable in meeting the National Electricity Objective***
- ***the Australian Energy Regulator's efficiency threshold applied to firms should be set close to, but below, the level of the most efficient firm.***

8.7 The regulator's benchmarking practices

The path to more sophisticated benchmarking requires supportive actions by the regulator.

Acquiring, sharing and using data

Due to the rulings in AEMC (2012a), network operators are already collecting greater amounts of data specifically for benchmarking purposes, while the AER is standardising its data collection and benchmarking processes (box 8.5).

There remains a further question over the extent to which data should be made publicly available. Several commentators have emphasised the importance of putting data in the public domain in order to allow greater transparency, and to allow stakeholders to undertake their own analysis (Lawrence 2009). Information and data on network characteristics are often only publicly available in high-level aggregates, whereas detailed data is often subject to confidentiality concerns.[10] However, network businesses are natural monopolies, where confidentiality is not as justified as it is for businesses operating in the competitive market. Accordingly:

- most data required to assess business performance should be made publicly available. This would allow rigorous analysis of network performance by customer groups and researchers. This would increase the capacity for customers to act in the negotiating role set out in section 8.4 and in creating public pressures for improved efficiency (section 8.5)
- even where data are genuinely commercial-in-confidence, consumer groups involved in negotiations under draft recommendation 8.4 and independent researchers should be able to access the data. This access should be subject to requirements that they do not divulge publicly the information either directly, or in a way that identifies specific businesses. Such arrangements are routine for other sensitive information (for example, survey data sets collected by the ABS and administrative records from major government agencies).

To give effect to the better dissemination and use of these data, the AER needs to develop systematic and easily used databases, and publish more information on how businesses are performing. The annual 'State of Energy' reports are useful, but the information provided has reduced over time. The 2008 report provided more than

[10] All data collected by the AER through Regulatory Information Notices (or other compulsory processes) are confidential. In the Commission's own experience, the sourcing of detailed data for the purposes of this inquiry has been met with various responses from networks, ranging from free unfettered use to complete anonymity.

320 pages of information, while the 2011 report was 120 pages in length. (This is in contrast to the exponential growth in the length of regulatory proposals and determinations.)

Box 8.5 **The AER's information strategy**

The AER's information strategy includes reviewing the data definitions of key information required to undertake economic regulation, and developing:

- benchmarking measures for electricity network capex, operating expenditure and, if appropriate, total expenditure
- benchmarking measures to compare the relative efficiency of regulated energy businesses, with an initial focus on electricity distribution
- a performance report for gas distribution networks, commencing with Victoria for 2009-10.

It also intends to expand the electricity distribution performance report to include network businesses from ACT, New South Wales, Queensland and South Australia for the 2010-11 report, Victorian businesses in the 2011-12 report, and Tasmanian businesses in the 2012-13 report.

Source: AER (sub. 13, p. 18).

In-house expertise

While raw data is valuable, a major role for benchmarking is to transform complex data into meaningful performance measures. As discussed in chapter 4, this often entails high-level technical expertise. While the AER should continue to engage external consultants,[11] an in-house capacity to undertake sophisticated analysis would have significant benefits. It would:

- better inform the collection of data relevant to best practice analysis
- improve the AER's capacity for intelligent and demanding outsourcing. Outsourcing requires sufficient in-house capability to discriminate among the various consultants. Moreover, there are likely to be greater benefits from outsourcing if the AER can absorb the research results it receives. (In the business world, an internal research capability is not only valuable in its own right, but because it raises the absorptive capacity of the business to others' ideas — PC 2007.)

11 The AER already routinely uses external consultants for economic and engineering advice, such as Nuttall Consulting (2010a) in the Victorian distribution network determinations, and Schweinsberg et al. (2011) on European benchmarking practices. But currently, it has limited current in-house capabilities in this area.

- allow the AER to interpret and communicate any technical results in an accessible way to non-experts.

Maximising the AER's capacity to learn

One particularly important aspect of acquiring and retaining internal expertise is a greater capacity for learning within the AER, and a more general capacity to interpret the revenue proposals of businesses.

A major problem besetting any method for determining the benchmark efficient costs of a business is that there is no recognised standard against which to test the accuracy and reliability of the estimated costs.[12] In effect, there is no agreed benchmark for verifying *either* bottoms-up or benchmarking models against the 'true' cost.[13]

Given that businesses have strategic interests, it seems likely that, after considering the businesses' processes and the detailed consultations that follow, the AER is in the best position to determine the best, unbiased estimate of their true costs. For the reasons outlined in chapter 5, that may be different from the AER's actual determination reached under the Rules. However, draft recommendation 5.6 proposes that if there is any divergence between the two estimates, the AER would also publish its preferred estimate. The AER can then over time compare the more estimate derived from a more bottoms-up approach with the simpler ones derived from aggregate benchmarking analysis. Over time, if benchmarking models improve, they should converge on the true estimate (in the fashion depicted in figure 8.4), improving their wider use, without as much bottoms-up testing.

Indeed, two immediately useful exercises in this vein would be for the AER to:

- reveal its preferred estimate of capex and opex arising from *past* determinations and examine how these estimates compare with the predictions of simple benchmarking models. That would provide an early test of the value of 'primitive' benchmarking

12 The situation is different from many other tests — such as the accuracy of medical diagnostics (confirmed through assays) and clocks (confirmed by reference to the US National Institute of Standards and Technology's highly accurate clock).

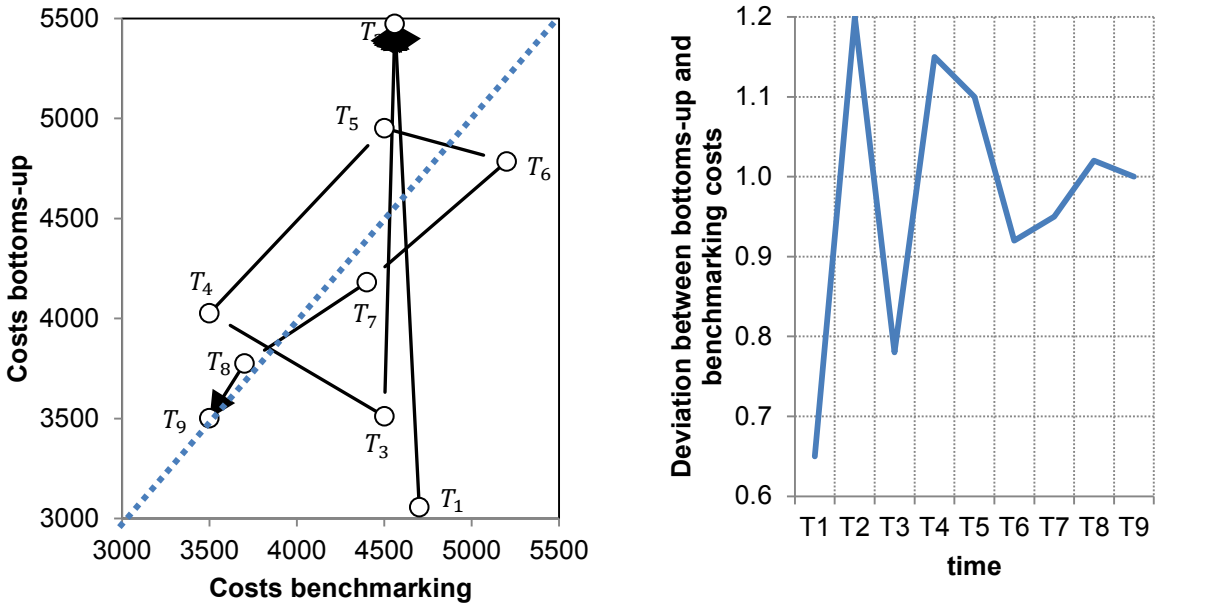
13 In theory, under a high-powered incentive regime (chapter 5), profit-motivated businesses will progressively reveal efficient costs, which could be an alternative estimate of 'true' costs. However, that process may be quite slow if lower-powered incentives apply or state-owned businesses (which may be constrained by a variety of non-commercial objectives imposed by their shareholders) continue their dominant role.

- examine the basis for variations in the Australian Energy Market Operator's top-down peak and average demand forecasts and the aggregate of distribution businesses' bottoms-up peak and average demand forecasts, since these are important ingredients in the determinations of revenue allowances and, in some cases, prices.

Given its importance to actual revenue determinations, the latter is the greatest priority.

Figure 8.4 **Convergence between benchmarking models and bottoms-up cost estimates**

A speculative illustration for a single business



a The graph on the left hand side shows the relationship between the bottoms-up and benchmark estimate of costs from T1 to T8. Full convergence occurs if the two estimates are the same, which means they would lie on the 45 degree line. At T9, the two estimates have converged. The right hand chart shows the *ratio* of bottoms-up cost to the benchmarking costs over time, showing how they move closer together over time (shown as reduced variance).

DRAFT RECOMMENDATION 8.6

The Australian Energy Regulator should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.

DRAFT RECOMMENDATION 8.7

The Australian Energy Regulator should make all benchmarking input data publicly available (recognising that the businesses being benchmarked are regulated monopolies) except where the data can be demonstrated to be genuinely commercial-in-confidence.

Where the latter holds, the Australian Energy Regulator should still make the full datasets available to:

- ***independent researchers who are using the results for non-commercial purposes***
- ***the consumer group involved in any negotiations described under draft recommendation 8.4***
  - ***but subject to statutory requirements for non-disclosure of information predetermined as commercially-in-confidence, drawing on existing models for data protection.***

DRAFT RECOMMENDATION 8.8

When making its revenue allowance determinations, the Australian Energy Regulator should make judgments about capital expenditure forecasts that take account of any discrepancy between the Australian Energy Market Operator's top-down peak and average demand forecasts and the aggregate of distribution businesses' bottoms-up peak and average demand forecasts.

The Australian Energy Regulator should use benchmarking of the discrepancies between previous expenditure forecasts and actual outcomes by different parties to inform that process.

Collaboration

While there are several obstacles to international benchmarking, it may still provide useful information (chapter 4), and businesses and governments already undertake such analysis. International collaboration between regulators, academic experts and global benchmarking specialists may improve the validity of international benchmarking. This has been long-recognised (Jamasb and Pollitt 2001, and Farrier Swier Consulting 2002), but the mechanisms for achieving it are still incomplete.

International collaboration would involve the consistent collection, auditing and reporting of data, and shared approaches to reporting results and the statistical

testing of models.[14] This would facilitate meta-studies, which help identify common variables that lead to robust benchmarking results. For example, if many (rigorous) individual country studies find that a limited set of consistently defined explanatory variables perform well in measuring industry costs — across diverse regulatory and operational environments — it suggests that such methods may be reasonably robust in any country.

Collaboration could also have other benefits, such as:

- increasing diffusion of best practice benchmarking techniques and data construction (such as meaningful measures of capital), which would build expertise and knowledge
- facilitating contacts between experts for solving technical and practical problems in benchmarking
- providing lessons and case studies on the pitfalls and unexpected benefits of benchmarking. This report has benefited from the experiences of Ofgem in the United Kingdom and FERC in the United States
- making it easier for secondments between agencies
- supporting external peer review of specific regulator's benchmarking analysis.

Transparency, consultation and communication

Section 8.3 has already spelt out the need for stakeholder involvement in developing benchmarking models. But, equally, they (and experts) should have a role in commenting on results (which should all be public), encouraged to undertake their own analysis, and have the information required that would allow them to replicate any models.

From a scientific perspective, the AER should adopt processes that increase the quality of the analysis. This would involve independent expert peer review of benchmark models to:

- establish their ongoing relevance, sensitivity to assumptions, and scientific validity (including the performance of any statistical models against accepted

[14] There appears to be greater efforts for international collaboration in water utility benchmarking than in electricity, with benchmarking consortia established for the Americas, Africa, and internationally (Berg 2010, p. 62). In utility regulation generally, the Public private Infrastructure Advisory Facility, the World Bank, and the Public utility Research Center of the University of Florida have created a collaborative online repository of material on infrastructure regulation (http://www.regulationbodyofknowledge.org). However, this is more a collection of references and training tools, than a resource for benchmarking and data collection.

standards — including confidence intervals, parameter stability, and specification testing, as set out in chapter 4)

- assess the modelling strategy used to produce the results
- consider the policy implications of model and parameter misspecification
- assess whether the AER has adopted best practice models.

It is also important for the AER to disclose the impacts of factors outside the control of businesses, but that may be controllable by governments (since, as noted above, these are important for policy and regulatory development).

While the key role of benchmarking is the determination of efficient revenue allowances, the AER would also need to communicate the results to their disparate stakeholders in an accessible way. As Berg (2010, p. 56) has colourfully noted: avoid 'sensational factoids', but use clear presentation methods for experts and lay audiences.

DRAFT RECOMMENDATION 8.9

The Australian Energy Regulator should collaborate with other leading regulatory agencies, academic experts and global commercial benchmarking specialists to enable robust meta-analysis of electricity network benchmarking results from individual country (and where credible, multi-country) studies. The collaboration should include cooperation in developing:

- ***the most meaningful measures of performance***
- ***consistent data collection***
- ***consistent reporting of results***
- ***best-practice analytic frameworks.***

DRAFT RECOMMENDATION 8.10

The Australian Energy Regulator should submit its major benchmarking analyses of electricity networks for independent expert peer review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to gauge the degree of uncertainty in the results.

DRAFT RECOMMENDATION 8.11

The Australian Energy Regulator should make its benchmarking results publicly available, with:

- ***accessible reporting of the results to inform consumer groups, network businesses, and others***

- ***disclosure of the importance of factors outside the control of businesses, but that may be controllable by governments***
- ***publication of the modelling strategy used to produce the results***
- ***the sensitivity of the results to changes in key assumptions***
- ***the performance of any statistical models against accepted scientific standards, including confidence intervals, parameter stability, and specification testing.***

Practicality and compliance costs

Data collection and modelling imposes costs on the regulator and the businesses. Accordingly, the principle should be to only collect information or use processes likely to produce net benefits. A measure should not involve onerous data obligations or take too much time to prepare.

The AER considered that benchmarking methods might reduce compliance costs for businesses:

> Unlike the current building-block approach, benchmarking does not unrealistically, burdensomely and intrusively aspire to duplicate or exceed the knowledge of business operation possessed by decentralised decision-makers in regulated entities. Rather, the informational and regulatory burden of a benchmarking program is limited to relative knowledge – a knowledge that only need pertain to relative performance. (ACCC/AER 2012a, p. 168)

This seems overly sanguine, since detailed bottoms-up modelling is unlikely to be displaced over the medium term. Moreover, testing the validity of benchmarking models (using the learning process set out earlier) requires both forms of information. Consequently, the informational burdens are likely to rise, not fall (and this is one of the reasons why the AER itself will require further resources, as discussed in chapter 21). That should change as the AER (and its international collaborators) develop better models and identify the most important data items.

In the meantime, the AER should routinely re-assess its benchmarking approaches, the resources it uses in benchmarking, and the compliance burdens that its data and consultation requirements impose on businesses. These assessments should be publicly available. The overall costs of collecting and analysing data for benchmarking purposes should be reviewed independently after five years.

DRAFT RECOMMENDATION 8.12

The Australian Energy Regulator should periodically examine its detailed benchmarking methodologies and processes to assess their compliance costs for businesses and the costs for the Australian Energy Regulator. It should compare these costs with the likely benefits when determining the appropriate frequency and type of detailed benchmarking. In undertaking such assessments, the Australian Energy Regulator should consult closely with network businesses.

The Australian Energy Regulator should make all such assessments publicly available.

The overall costs of benchmarking should be subject to independent review after five years.

8.8 Conclusion

Although Australia has been relatively 'unsophisticated' in its use and application of regulatory benchmarking in the electricity sector, this is likely to change in coming years with improvement in the AER's data collection and modelling capabilities. An increase in benchmarking for diagnostic and informational purposes is likely to be feasible in the near term. Over time, repeated use of benchmarking models (as well as ex-post analysis) will improve the reliability of the models' estimation of network efficiencies, and increase the potential for it to have greater weight in regulatory decisions. Some changes in the Rules will be required to facilitate this. Whilst there may be some shorter-term burdens for network businesses in providing additional data to the AER, improved confidence in benchmarking has the potential to simplify determinations and lower overall costs, leading to benefits for network businesses and consumers.