Australian Government
Productivity Commission

Electricity Network Regulation

Productivity Commission
Issues Paper

February 2012

How to participate in this inquiry

The Commission has released this issues paper to help people and organisations contribute to the inquiry. It sets out the scope of the inquiry, the issues about which the Commission is seeking comment and information, the Commission's procedures, and how to make a submission. The paper is not intended to be exhaustive — please raise any matter you see as relevant to the inquiry. Nor should you feel obliged to comment on all the matters raised in this paper.

Philip Weickhardt (presiding) and Wendy Craik are the Commissioners on the inquiry.

Key inquiry dates

Initial submissions due	16 April 2012
Release of draft report	September/October 2012
Second round of submissions due	November 2012
Public hearings	November/December 2012
Final report to Government	9 April 2013

Submissions can be made:

By email: electricity@pc.gov.au By fax: (02) 6240 3311

By post: Electricity Network Inquiry
Productivity Commission, GPO Box 1428
Canberra City ACT 2601

See below on how to make a submission. All public submissions will be available from the inquiry website at http://www.pc.gov.au/projects/inquiry/electricity. If you do not receive notification of receipt of an email message you have sent to the Commission within two working days of sending, please contact the Administrative Officer (see below).

Contacts

Administrative matters:

Jill Irvine (02) 6240 3223 or Christine Underwood (02) 6240 3262

Other matters:

Michelle Osborne (02) 6240 3354; Ineke Redmond (02) 6240 3310 or
Ralph Lattimore (02) 6240 3326

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.

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How to submit a submission

Each submission should be accompanied by a submission cover sheet (attached below and also available on the inquiry webpage. Submissions can be sent by email, fax or post to the addresses shown above. For privacy reasons, any submission received from an individual will have all personal details removed before it is published on the website.

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Track changes, editing marks, hidden text and internal links should be removed from submissions before sending to the Commission. To ensure hyperlinks work in your submission, the Commission recommends that you type the full web address (eg http://www.referred-website.com/folder/file-name.html).

Electricity Network Regulation Inquiry

Australian Government
Productivity Commission

SUBMISSION COVER SHEET

(we do not publish this page)

Please complete and return this cover sheet with your submission to:		
Electricity Network Regulation Productivity Commission, GPO Box 1428, Canberra City ACT 2601	**OR**	By fax to either Jill Irvine or Christine Underwood (02) 6240 3311 By email: electricity@pc.gov.au

Person

Organisation and position (if relevant)

Street address

Suburb/town *State* *Postcode*

Email address

Phone ( ) *Fax ( )* *Mobile*

Please indicate if your submission:

☐ contains NO material supplied in confidence and can be placed on the Commission's website

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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 judgments. 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]

1 Scope of the inquiry

Background

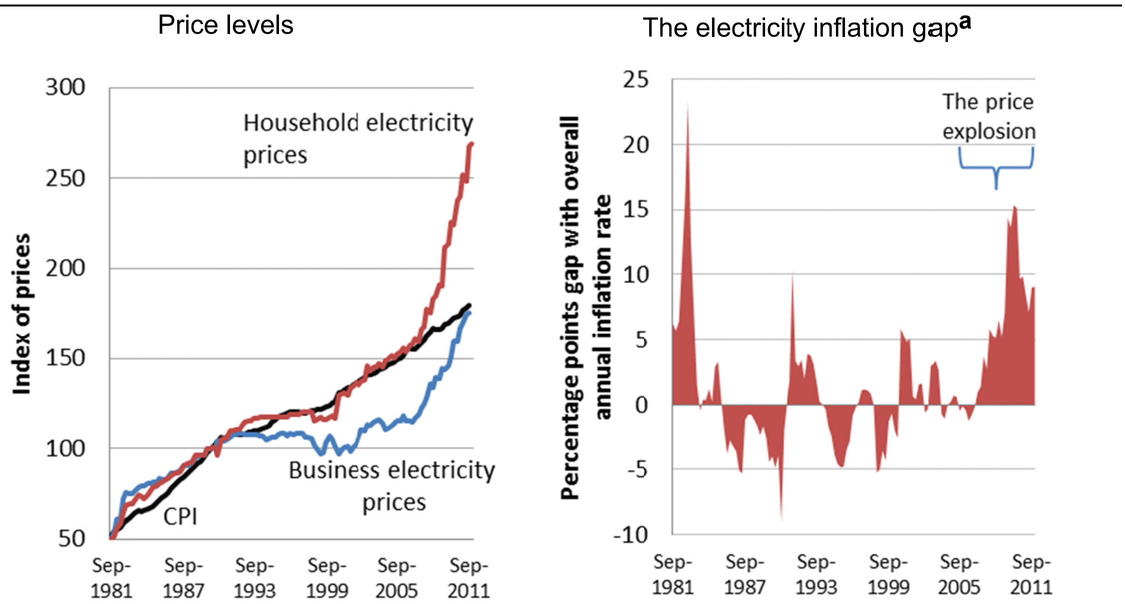
Nearly all households, businesses and other entities use electricity. Ensuring a reliable, affordable and sustainable system requires efficient investment, pricing and regulation. This inquiry is directed at electricity network services (mainly comprising substations, poles and electric wires) that transmit and distribute power from generators to end-users in the National Electricity Market (NEM). In 2009-10, the costs of network services represented between 40 and 50 per cent (or $500 to $600) of a typical annual household electricity bill (AER 2011a, p. 6; ABS 2011).

Rising network costs have been the primary driver of electricity price increases over the last five years. Until the mid-2000s, Australian retail electricity prices grew at around the same rate as economy-wide inflation, but then began to rise rapidly (figure 1). From June 2007 to December 2011, Australian retail electricity prices rose by around 69 per cent, while general inflation increased by around 14 per cent. Electricity prices rose most strongly in New South Wales (NSW) over this period (79 per cent), nearly 10 percentage points higher than any other jurisdiction in the NEM. Apart from Victoria and the Australian Capital Territory (ACT), network costs have been the largest recent contributor to price increases (AER 2011a and AEMC 2011e). Future retail electricity prices — at least partly locked in through regulatory agreements — are projected to increase by 29 per cent from 2011-12 to 2013-14, with network costs the main contributor.

In a separate exercise from this inquiry, the Productivity Commission found significant reductions in measured multifactor productivity in the electricity sector as a whole over the past decade (figure 2), and will soon release a staff paper exploring some of the reasons for this (Topp and Kulys 2012). The Independent Pricing and Regulatory Tribunal (IPART 2010) found that in NSW there were more pronounced productivity reductions for network businesses than for generators.

The price increases and productivity reductions coincided with major regulatory changes for electricity transmission and distribution, which were introduced in 2006 and 2008 respectively. As the goal of these regulations was ‘to improve the environment for investment’ (AEMC 2006, p. iv; AER 2011, pp. 3-4), some price increases could be expected, as would some reduction in productivity, given that investment must be made ahead of its full utilisation. However, some parties claim that much of the price increase and productivity slowdown can be attributed to two interconnected flaws in the post-2008 regulatory arrangements for electricity networks.

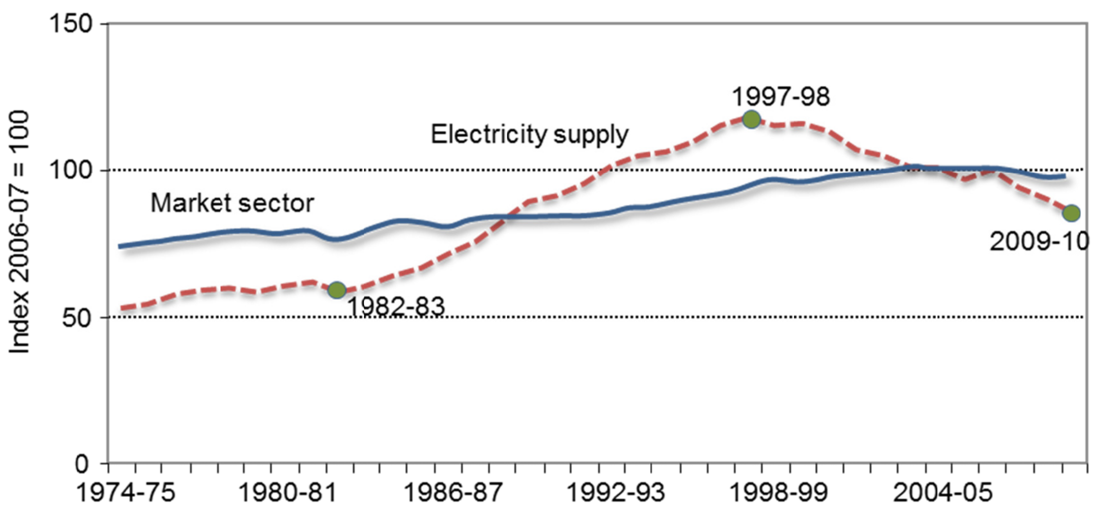
Figure 1 Electricity prices have been rising steeply in recent years



[a] The electricity inflation gap is the difference between the year on year percentage price change in household electricity prices and the all goods CPI inflation rate. Data are from September 1981 to December 2011. The data relate to all Australian electricity prices, not just those in the NEM, but the trends will be similar.

Data source: ABS 2012. *Producer Price Indexes, Australia, Dec 2011*, Cat. No. 6427.0, 25 January; ABS 2012, *Consumer Price Index, Australia, Dec 2011*, Cat. No. 6401.0, 23 January.

Figure 2 Measured electricity sector productivity has been falling[a]



[a] Multifactor productivity estimates, which takes account of productivity growth 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).

In particular, the Australian Energy Regulator (an agency within the Australian Competition and Consumer Commission, with responsibility for regulating the NEM), various electricity user groups and the Garnaut review of climate change policy argue that regulatory incentives encourage excessive investment ('gold plating') in distribution networks, which requires price increases to fund the infrastructure, and that wastes resources best used elsewhere in the Australian economy. They also claim that the regulated return to capital is excessive, directly leading to higher prices. In particular, the Australian Energy Regulator (AER) has claimed that some price rises it had allowed were 'difficult to justify' (AER 2011a, p. 4), and arose from deficiencies in chapter 6 of the National Electricity Rules that it was obliged to enforce. Indeed, Major Energy Users have suggested that the relevant rules had 'more than reversed the benefit gained from energy reforms initiated since the mid-1990s' (Major Energy Users 2011, p. 3).

In his update on climate change, Professor Ross Garnaut also argued that there were barriers to interstate transport of power due to inadequate investment in inter-regional electricity transmission (interconnectors), a result he ascribed to fragmented and parochial transmission planning, market design flaws and other regulatory failures (Garnaut 2011, pp. 153-155).

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. This inquiry is intended to test some of the approaches to that issue.

What has the Commission been asked to do?

The Australian Government has asked the Commission to undertake a 15-month inquiry into:

- 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, which are the high voltage transmission lines that transport power between the jurisdictions in the NEM.

Benchmarking

'Benchmarking' is applied by utility regulators across the world, although there are many complexities in defining what it is, what indicators should be used and how it can be applied in practice. At its most general, benchmarking measures a business's efficiency against a best-practice 'reference' performance to uncover the prices and costs that would hold in an efficient market. Most commonly, benchmarking involves comparisons between similar businesses — usually over time — to identify their relative efficiency. An alternative approach is to determine the reference point using a bottoms-up model based on a single 'fictitious' efficient firm. Regardless, the usual regulatory purpose of benchmarking is to set limits on revenue or prices to penalise inefficient businesses, while ensuring that there is a sufficient profit margin to reward efficient ones. However, as discussed below, benchmarking might also be used in other ways to promote efficiency.

The Australian Government has asked the Commission to consider the use of benchmarking under the regulatory framework applying to the NEM, as specified in the National Electricity Rules (often referred to as the Rules), and to provide advice on how different benchmarking methodologies could be used to enhance efficient outcomes. The Commission is to take into account any amendments to the Rules over the course of the inquiry (reflecting the multiple reviews currently in train — table 1).

The inquiry will not undertake elaborate benchmarking analysis of its own, but if feasible, will consider whether some of the concerns expressed by various stakeholders about large efficiency gaps between distributors have prima facie validity.

Given that the terms of reference relate to the NEM, they exclude arrangements for the generation, transmission and distribution of power in Western Australia and the Northern Territory. Accordingly, the Commission will not examine in any detail how benchmarking might be incorporated into the regulatory arrangements in those jurisdictions. However, it will consider any information from those networks that may assist in developing benchmarking models or in understanding the regulatory risks of different benchmarking approaches.

Interconnectors

Interconnectors are high voltage transmission lines that allow power to be traded across state and territory borders, increasing competition between generators and providing additional sources of power, which can assist with improving reliability. Trading in power between regions has implications for electricity pricing, the required network infrastructure, the need for generator capacity to meet end users' needs and access by the broader network to new renewable power sources. With the exception of one merchant interconnector, the NEM's six existing interconnectors are regulated under the Rules. The inquiry will examine whether the current regulatory regime is delivering efficient levels of network and generation investment across the NEM.

Table 1 What other major reviews are under way?

Review or rule change request	*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, & planning	Final report in June 2012
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 paper 20 October 2011 and 3 November 2011, Draft determination July 2012 and final in October 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 February 2012; draft report May 2012; final report September 2012
Review of Distribution Reliability Outcomes and standards (NSW)	Examines the extent to which investment in distribution networks reflect customers' willingness to pay for reliability	Issues paper November 2011; best practices paper January 2012; draft report May 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 July 2012; draft report November 2012; final report 4 months after SCER comments on draft
Optimisation of Regulatory asset 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 March 2012; any rule change June 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 (the RIT-D)	Consultation paper September 2011; draft determination in March 2012; and rule changes by July 2012
Potential Generator Power in the NEM	Definitions of any market power of generators for regulatory purposes	Technical paper December 2011; draft rule determination April 2012
Inter-regional transmission charging	Consideration of inter-regional transmission charging	Discussion paper August 2011; final rule determination October 2012
Other reviews/major papers		
Limited Merits Review appeal arrangements	Review of statutory merit appeal processes	Commencement in 2012
Energy White Paper (Australian Government)	Policy framework to address challenges in the energy sector	Draft report in December 2011; consultations in 2012
AER review of information collection processes	Aims to provide appropriate inputs into analytical tools	Implementation by June 2013

Other ongoing policy processes

The regulatory environment is evolving. Given this, the Australian Government has asked the Commission to take account of work being undertaken by the Standing Council on Energy and Resources (SCER, which comprises the relevant ministers from all jurisdictions), the Australian Energy Market Commission (AEMC), which is the independent rule maker, and the AER (table 1).

The Commission was requested particularly to focus on the implications 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 Government has asked the Commission to engage with the AEMC, the AER and the Australian Energy Market Operator (AEMO) in undertaking this review. The Commission will also consult with other Australian government agencies, key business and consumer stakeholders, and other interested parties in undertaking the review. The Commission will also consider international regulatory experiences in achieving efficient investment and pricing in networks and interconnectors.

As is the case with all Productivity Commission inquiries, the Commission's overarching objective in recommending any policy changes is to maximise the long-run benefits to the community as a whole, and that basic principle will guide the analysis undertaken in this inquiry.

Given the various ongoing reviews and the consultations associated with them, how can the Commission best add value? Do these reviews have the same broad objective as the Commission or are they more narrowly focused?

2 The National Electricity Market

The NEM is a highly elaborate system for managing the production and transport of power throughout eastern Australia.

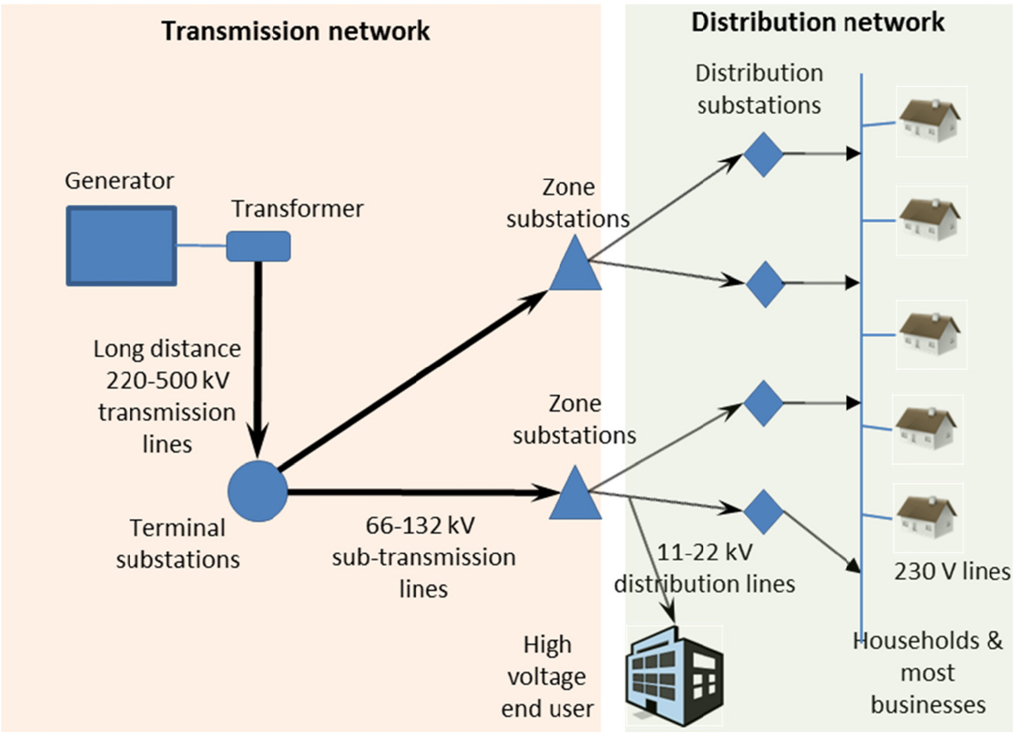
On the supply side (figure 3), the system comprises several components:

- *generators*, such as a coal- or gas-powered generator (the dominant sources), a wind farm or hydro-electricity plant
- *the electricity network* (the focus of this inquiry), which 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 (to lower transmission losses)
– high voltage transmission lines — mainly strung overhead on steel lattice towers — that transport power over long distances
– substations that convert very high voltage to lower voltage
– a 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.

- *retailers*, many of which are vertically integrated with the above suppliers.

Figure 3 **The transmission and distribution network**



Data source: Based principally on Powercor (2006).

In addition, 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 some competition with electricity distribution businesses in the installation, ongoing maintenance and repair of smart metering (Metropolis 2011).

In 2010-11, the NEM served around nine million customers and had a turnover of around \$7.4 billion (AER 2011a, p. 25). 305 generators fed the network of

5 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.

Although the information technology systems to control the system are sophisticated, much of the *costs* of the electricity network involve relatively mature technologies (a feature it shares with telecommunications).

The NEM is the most geographically dispersed electricity network in the world. The network comprises around 40 000 kilometres of high voltage transmission lines and 750 000 kilometres of lower voltage distribution networks (AER 2011a, 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. 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, which is why this is the main area of concern about whether investments are economically efficient. Interconnectors account for an estimated share of total network asset values of around 5 per cent. Transmission accounts for the residual assets and investment.

The NSW, Queensland and Tasmanian distribution networks are owned by their respective governments, whereas private entities own the South Australian and Victorian distribution networks. The 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). Some parties contend that private distribution businesses are more efficient than government-owned enterprises and that they respond differently to regulatory incentives, although this is strongly contested by others.

The electricity market is highly regulated and coordinated

The AER sets five-year revenue or price ceilings for electricity transmission and distribution networks in the NEM, based on expected costs during that period (AER 2011a, p. 57). This reflects that in each geographic segment, costs are minimised through supply by a single distributor — a natural monopoly. As such, there is no genuine capacity for new entry by a rival (unlike electricity generation). For example, an urban street would not have two sets of power lines owned by different suppliers. In the future, distributed generation may provide some competition to the network, but that prospect is not imminent.

The regulatory objective (referred to as ‘National Electricity Objective’) of the NEM is to promote 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 security. The overarching responsibility for energy policy rests with the Standing Council on Energy and Resources, a recently formed COAG standing council. It sets general principles, and can propose reviews by the AEMC. However, the AEMC holds the power to determine the Rules. The AER regulates network providers using the complex set of rules formulated by the AEMC. The objective of the regulator is to ensure that the projected revenues for operators can fund efficient investments in networks, while maintaining the reliability, safety and security of the services. The AER attempts to achieve this objective through investment controls, price limits and revenue caps.

The AEMO is also an important part of the institutional arrangements for electricity. It is structured as a corporation with a skill-based board comprising government and private members. It has responsibility for ensuring system security and managing the market. It takes bids and determines spot prices for generators, and ensures demand and supply are matched. AEMO also manages the key functions of 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 (Smith 2011).

The existing regulatory arrangements for the NEM are detailed and prescriptive (with the Rules being around 1300 pages in length). Notwithstanding the apparent certainty that some claim these detailed Rules provide, regulatory decision documents have apparently doubled in length every five years (Tamblyn 2011 and Biggar 2011), and there have been many appeals of the AER’s decisions.

Regulatory arrangements extend beyond the Rules. Governments regulate networks to ensure the reliability of supply, given the substantial costs of blackouts (power loss) and brownouts (reductions in voltage for minutes or hours, rather than fleeting falls). Governments play a role in planning for new investment in transmission lines. As noted above, in some states, government-owned enterprises hold all of network assets, which mean that these governments also have a direct stake in the supply of services. Renewable energy targets and various state and territory government feed-in tariff arrangements can also affect the structure of the grid and required investment.

Are there any other major regulations or policies that affect the electricity market that need to be considered when undertaking benchmarking or in understanding any of the possible obstacles to investment in interconnectors?

3 What is benchmarking?

Businesses that are subject to competitive pressures often assess their comparative performance, establishing data systems and governance arrangements to do so. Sharemarket valuations and takeover prospects often reflect judgments about a business's relative performance. In utilities regulation, such competitive pressures may be blunted because of monopoly and government ownership. Regulatory benchmarking represents an attempt to mimic commercial processes that assess performance so that regulators can make informed decisions about allowable prices, investment and incentive regulations.

Benchmarking measures a network supplier's efficiency against a reference performance. There are many different types of benchmarks, multiple ways of calculating benchmarks, different ways of using such benchmarks in utility regulation, and several criteria for discriminating between competing approaches (box 1).

Appropriate benchmarks depend on the purpose and type of comparisons.

Overall measures of inter-firm performance

One broad category of benchmarking assesses the extent to which a network provider is close to best practice after adjusting for factors *outside* its control (such as the topography of the area it must serve, the distance between customers, the number of hot days, and externally set reliability standards). One such benchmark would be the minimum long-run cost of providing network services, taking as fixed the operating environment of the provider (such as customer density and regulated service reliability standards). However, meaningful aggregate output measures are not necessarily easy to define (Diewert et al. 2009, pp. 73ff).

Under incentive regulation, a network provider would be rewarded if it were at, or close to, the aggregate benchmark. (A benchmark need not be defined by the best-performing firm, but could be specified as the average of a group of higher performing firms.)

Box 1 A coat of many colours: benchmarking

Benchmarking approaches and methodologies include:

- comparing the costs and performance of different network providers to identify best practice and maximum efficiency. In some cases, benchmarking can span various countries, though apparently this has proved challenging in electricity (Dassler et al. 2006)
- examining qualitative indicators about business practices
- examining trends in total factor productivity (TFP), which is the residual growth in output after taking account of changes in the inputs used to produce network services
- creating 'bottom-up' models of an efficient 'fictitious' supplier, built up from a detailed model of the infrastructure, operating costs, and demand conditions in the electricity market (Gómez-Lobo, 2007, p. 12)
- the use of aggregate and partial indicators
- simple ratios, index approaches and econometric approaches (corrected ordinary least squares, stochastic frontier analysis and data envelopment analysis).

Their practical use as a tool for creating incentives for better business performance also depends on balancing several criteria. A benchmark should:

- test what it claims to (efficiency in one or more meaningful dimensions) and without significant bias. A failure to adequately control for differences in operating environments can lead to biased measures or create perverse incentives (such as favouring capital expenditure over operating expenditures)
- allow a regulator to measure the relative or absolute degree to which a business is inefficient with sufficient precision, and do that consistently across time and jurisdictions. In many instances, this also requires that small variations in the quality of data used in benchmarking do not materially alter the results
- be transparent, so that stakeholders can scrutinise the model for its performance and develop it further
- provide sufficient certainty so that a network owner has the confidence to make major capital investments in long-lived assets
- not involve onerous data obligations or take too much time to prepare
- have limited susceptibility to manipulation or gaming
- be no more complex than is required to achieve the above criteria.

It is particularly important in benchmarking to ensure 'like with like' comparisons between network businesses. For example, costs are higher for network businesses with few customers per line length. Ignoring this could lead to such businesses being categorised as inefficient compared with businesses with high customer densities. A network provider under-rewarded using the wrong benchmark would not make efficient investments or other decisions, and could become insolvent, indicating the risks of badly configured benchmarks — a point made by some network distributors.

Partial indicators

As well as aggregate indicators, network benchmarking can also involve many different partial indicators, such as:

- the total cost per consumer divided by the lot frontage (the front width of property), with the former argued to be the best measure of performance and the latter the best driver of costs (Elder and Beardow 2003)
- measures of capital utilisation, such as the ratio of the average load to peak load over a period of time (the 'load factor')
- replacement investment as a ratio to the effective remaining life of existing distribution infrastructure (as a potential measure of premature retirement of assets)
- short-run actual costs borne by a network provider — with various measures of the cost of maintaining and operating the many components of network infrastructure, such as overhead lines, service connections and transformers (Turvey 2006b). These could be normalised for variations outside the control of network businesses, such as topography
- the degree to which different distributors outsource maintenance, software, smart metering or use other modern management methods
- the degree to which different distributors adopt demand management initiatives
- the extent to which a business meets reliability measures, such as the sum of the duration of each customer power interruption in minutes divided by the total connected customers averaged over a year.

As there may sometimes be tradeoffs between partial benchmark measures, it can also be useful to assess whether high scores on one measure are associated with low scores on others.

What are the best (and worst) aggregate measures of performance, and why is this so? In which contexts (Australia and elsewhere) have these been most credibly been used?

What partial indicators are meaningful? Are there particular parts of network businesses that are easier to benchmark? What are these, why is it easier, and what have benchmarking studies revealed?

Are there criteria beyond those identified in box 1 that are useful for discriminating between good and bad benchmarking tools and approaches?

What are the weaknesses and advantages of full versus partial measures for benchmarking?

What methods should be used for benchmarking (indexes, corrected ordinary least squares, data envelopment analysis, simple ratios), and what are their strengths and weaknesses?

Using benchmarking to assess regulatory performance

Inefficiency can arise for several reasons. Practices controlled by the firm — such as poor cost discipline — may be one source. Shortcomings in regulatory or other policy settings that influence a firm's efficiency may be another. Benchmarking tends to focus on the former, but could also examine the gains from the most efficient reliability standards, allowing time of day pricing for customers, or some other best practice policy (an approach taken by McLennan Magasanik Associates in its 2007 report to COAG).

One of the potentially useful aspects of international or interstate comparisons of productivity is that they may detect policy and regulatory settings outside the control of the business that may frustrate its efficiency. Some international benchmarking studies of electricity and other sectors have sought to explain the divergence in international performance of businesses in terms of the policy and regulatory settings they face, and not just managerial performance (BIE 1995, Mota 2004, Productivity Commission 2011). Indeed, some of the impetus for regulatory reform of Australian utilities a decade ago arose from evidence about its beneficial impacts in overseas countries.

In that case, policy reforms aimed at improving efficiency would need to combine incentives to encourage managerial efficiency with separate efforts to implement the best regulatory arrangements. In this vein, IPART (2010, p. 49) has 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.

Could benchmarking be used to assess the effectiveness and efficiency of different regulatory settings (such as reliability standards)?

Are there examples where regulatory benchmarking has been used in electricity networks in Australia or overseas?

Are there any other broad benchmarking approaches not discussed above, and where and how have these been used?

4 But is benchmarking practical?

Many accept benchmarking (and its use in incentive regulation) as a conceptually sound approach. However, the question is whether it is practical.

Certainly, benchmarking is actively used in performance measurement.

- There is a large international empirical literature on benchmarking utilities generally, as well as electricity network providers.
- Several countries already use benchmarking for electricity regulation (such as the United Kingdom, Finland, the Netherlands, Norway, New Zealand and some jurisdictions in North America), albeit often as a complement to other approaches (Filippini et al 2005; AEMC 2011f). A recent review identified Australia as generally unsophisticated in its use of benchmarking in electricity (Haney and Pollitt 2011), suggesting scope for its better use in Australia.
- Some Australian studies have already been undertaken (such as those by Mountain 2011, Mountain and Littlechild 2010, Nuttall Consulting 2010, and Reynolds 2011). For example, Reynolds estimated long-run marginal costs for Australian distributors and found significant disparities in costs that could not be attributed to customer density. Mountain found large differences in the performance of Australian distribution businesses, with government-owned enterprises apparently performing particularly poorly (and with worsening efficiency outcomes over time). On the other hand, the various studies of operating expenditure reported by IPART (2010, pp. 57ff) did not find marked differences between various Australian distributors. There have been a large number of total factor productivity (TFP) growth studies (at the Australian and state level, covering different periods and using different definitions of inputs), but for overlapping periods, these have found broadly consistent national patterns (Topp and Kulys 2012).
- Many studies of comparative productivity performance have been undertaken for Australian gas distribution (Economic Insights 2009), which share some common features with electricity networks.

- Network businesses gauge their current performance by comparing it with their past performance. They also undertake inter-firm benchmarking (both within Australia and globally) to assess their own performance for management purposes. Indeed, many electricity businesses have provided data to form global databases for benchmarking purposes — such as the International Transmission Operating and Maintenance Study (ITOMS) and the High Density Urban Utility Forum. This suggests that benchmarking may provide at least some useful information for management, though it is an open question whether regulators can use the results meaningfully. IPART (2010, p. 48) cited ITOMS results for the maintenance performance of the NSW transmission business, TransGrid, which appeared to be one of the global leaders for this expenditure category.

However, notwithstanding the above, many claim that it is not currently possible to make valid 'like with like' comparisons *for regulatory purposes*, because so many influential cost drivers vary between network businesses. For instance, Beardow (2010) contests the findings by Mountain discussed above, arguing that operational differences — such as customer density and asset vintages, not ownership — explain the different cost structures.

The Australian Competition Tribunal (2012) has recently ruled that the AER's benchmarking of the unit costs of vegetation clearance around overhead wires provided reasonable grounds for dissatisfaction with the forecasts made by distribution businesses. However, it also found that the AER's failure to undertake the benchmarking on a fully 'like by like' basis meant that the AER's alternative forecasts were also not reasonable (with the matter referred back to the AER).

A recent AEMC review of the possible use of TFP as a regulatory incentive tool — one form of benchmarking — effectively reached the same conclusion about the difficulty of like with like comparisons.[1] It argued that TFP-based benchmarking was ill-suited to transmission businesses due to the small numbers of service providers, their inherently lumpy investments and the difficulties in measuring outputs. For distribution businesses, it concluded that existing data were not consistent, reliable or robust enough to use the TFP approach. However, it considered that, over the longer-run, TFP may be useful in achieving the objectives of the National Electricity Objective for distribution businesses, and that the next step should be data collection.

[1] The review was prompted by a request by the Victorian Government for a Rule change to allow the use of a tops-down TFP approach in AER determinations.

Is imperfect benchmarking still useful?

Regulators sometimes have to confront the reality of developing 'plausible policies for an imperfect world' (Baumol 1967). In looking at the issue of practicality, the question may not be whether benchmarking could supplant existing approaches for setting revenue caps in electricity networks (the main issue at which the AEMC's review was directed), but whether they could helpfully contribute at least partly to regulatory determinations. Moreover, whatever conceptually and practically might be the best benchmarking approach, the data underpinning analysis will always have some limitations. In that case, the issue is whether there are available data and methods that are good enough for useful analysis.

Defining what 'useful' means is not straightforward. For instance, it may be that one useful aspect of benchmarking could be its narrow use in evaluating very specific aspects of the forecast costs of a distributor (such as whether cost estimates for clearing vegetation around transmission lines were reasonable or not). The AER has used such benchmarking approaches (among others), although its approach to benchmarking has differed across determinations.

Alternatively, aggregate but imperfect forms of benchmarking might be used to broadly corroborate any conclusion by the regulator about forecast spending based on detailed information provided by network businesses in the building block proposals. If not, it could prompt either adjustments to the allowed aggregate spending (were the Rules to permit this) or more assessment of the detailed data. Such benchmarking might also address the concerns of some network businesses that they are being unfairly depicted as inefficient.

In theory, benchmarking could also be used to test whether old assets, still being rewarded as part of the regulated asset base of a business, should be excised. Technological or market changes can make older assets redundant in normal businesses.

Ultimately, benchmarking is only a means to an end and not a goal in its own right. As a result, the Commission must weigh up whether there are alternative policies that could more efficiently meet the National Electricity Objective. Equally, there could be a need for complementary policies to make benchmarking an effective tool.

Is there a big enough problem to justify new approaches to benchmarking and to incorporate it into regulatory incentive arrangements? To what degree could perceptions of inefficiency reflect the newness of the current regulatory regime or a failure to sufficiently adjust for the differing starting points of different distribution businesses?

How do existing network suppliers assess the efficiency and performance of their own businesses and how do they use these results? Could these results have relevance to regulatory benchmarking, and if not, why not?

How should benchmarking be used by the regulator? For example, to what degree could and should it be used as 'high-powered' incentive regulation; as a basis for determining the weighted average cost of capital and efficient spending; or as public information to provide moral suasion for efficiency?

What is the magnitude of the benefits from using benchmarking in regulatory decision-making in terms of lower unit costs or other performance measures?

What are the lessons from overseas about their benchmarking approaches, and what aspects should Australia copy or avoid?

To what degree could the AER use international benchmarking?

How can a good benchmarking model be identified since data and methods always have some imperfections?

Is there value in 'rough and ready' benchmarking models and how would these be used?

What are the most important control factors for benchmarking network businesses (for example, lot frontage, asset vintage, topography, weather variations, customer types, reliability standards, ratio of peak to average demand, and any strategic behaviour by generators and retailers)? What matters less?

What are the main differences in the potential for, and methods of, benchmarking transmission versus distribution businesses?

Should benchmarking results and methodology be publicly available, and if not, why not?

What are the consequences of errors in benchmarking? To what extent do these costs vary for positive versus negative errors? How could the costs of any errors be reduced?

To what extent would it be helpful to give the AER some discretion in deciding how much weight should be given to benchmarking and other tools when making regulatory determinations?

What if any, alternative policies may be superior to benchmarking? What, if any, policies could complement the use of benchmarking?

The importance of testing rival explanations

A potentially important check on any benchmarking exercise— even one that has attempted to control for some variations in the operating environments of distributors — is to distinguish between rival explanations for differences in performance and inefficiency.

While stakeholders have provided some partial evidence of a problem in efficient provision of network infrastructure, there are questions about whether the existing empirical evidence for claimed overinvestment and excessive price rises (such as those cited by Garnaut) fully considers rival explanations.

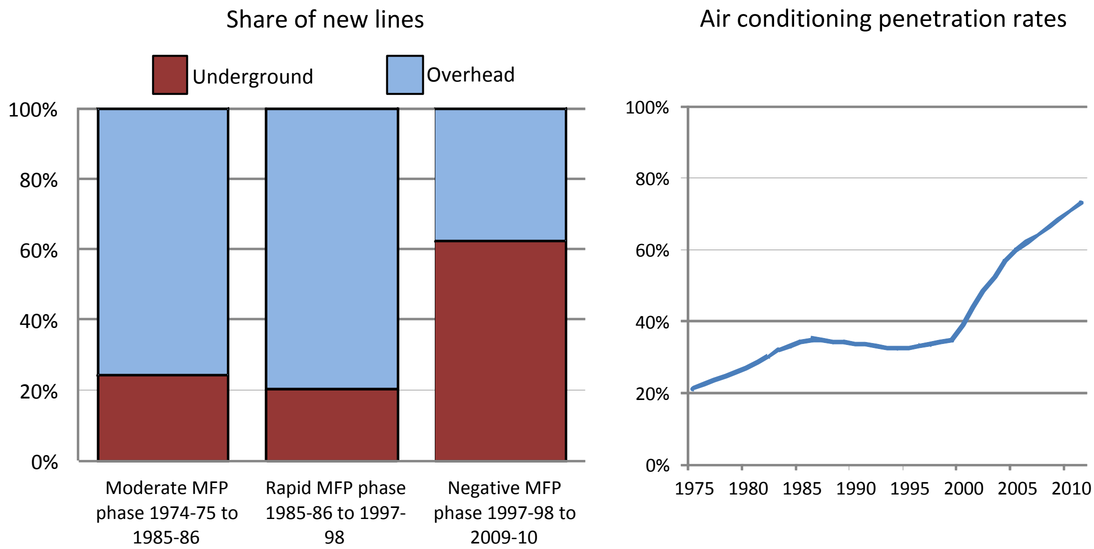
Some of the contributors to the price increases have reflected input cost increases — which are typically outside the control of either network businesses or government. For example, rising steel prices have increased costs (AER 2009, pp. 485ff). The drought in the late 2000s reduced water supply to hydroelectricity generators (the energy source) and to coal powered generators (as a coolant), reducing the use of lower-cost generators (Plumb and Davis 2010).

In the case of capital expenditure, the increased costs associated with installing underground cables in urban areas, the need to replace ageing assets, and increasing peak load demands have raised capital requirements (figure 4 and Topp and Kulys 2012). Peak demands have significant effects on the need for generating and network capacity. The Queensland Government (2009) estimated that around 10 per cent of electricity distribution network capacity is built to meet a level of demand, which only occurs for approximately 1 per cent of the time. These are hot days when large numbers of people turn on air conditioners at the same time. Some also claim that the recent investment surge is not unusual, but is typical of an industry in which there have been repeated cycles of low and high investment rates.

However, while these factors may lead to additional investment, this need not imply that the investment is efficient. Accordingly, a benchmarking exercise may need to assess the degree to which capital expenditures associated with these factors represent genuine quality improvements, taking into account that the value of such improvements to end users may not match their costs and that sometimes less costly non-network solutions (such as demand management) may be available.

It is also important to assess whether network businesses are efficiently managing their large capital spending. Significant capital spending overruns are not uncommon for large projects in many industries, but they are often a function of the project management and governance arrangements of the businesses concerned.

Figure 4 Underground cables and air conditioning trends have contributed to greater capital expenditure



Data source: Topp and Kulys (2012) for Australia as a whole.

What are the principal reasons for the apparent decline in the productivity of the electricity networks and for the associated increases in electricity prices? In particular, what have been the effects of rising input prices, past underinvestment, building ahead of use, rising peak demand, underground cabling and requirements for reliability requirements? To what extent have investment responses to the above factors been economically efficient?

To what extent have rising network costs reflected failures to correctly define project scope, to adequately control project costs and 'gold plating'?

If there has been gold plating by network businesses, how has this been realised (premature investment, over-specification of network elements, excessive reduction in service interruption risks)?

What is the evidence about the comparative roles of the above factors?

To what extent have Garnaut, Mountain and Littlechild identified genuine inefficiency in electricity networks?

5 The interaction of benchmarking with the regulatory framework

Achieving the goals of the National Electricity Objective through network regulation is difficult — both conceptually and practically. The Rules and their application by the regulator may not produce the desired outcomes. Flaws in the Rules may lead to inefficient investment and pricing outcomes. On the one hand, investment may be excessive or poorly allocated if the regulatory arrangements guarantee relatively high returns for investment, regardless of its efficiency. On the other hand, investment may not be sufficient to meet long-run demand if prices are too low or the regulatory arrangements otherwise penalise efficient business investment. Insufficient investment may result in congestion, blackouts and longer-term energy security problems.

Benchmarking may provide a 'window' on inefficiency. However, any use of benchmarking, either as a source of information or as an explicit regulatory instrument, depends on understanding how existing arrangements may affect network providers' incentives. In effect, is it worth looking through the window and in what direction should you look?

While most of the specific details discussed below relate to distribution businesses — where the regulator and energy users have identified the biggest problems — they also can relate to transmission businesses (though the Rules for the latter vary in some significant ways from those for the former).

The process for approving future investment and operating expenses

Electricity network providers must prepare forecasts of spending for a regulatory period of five years based on so-called 'building blocks' proposals. These proposals provide exhaustive detail about proposed investment and operating expenditure. For instance, just one element of a proposal might be an upgrade of a substation. The proposal would have to provide a detailed breakdown of the costs and extent of the upgrade. The proposal would also provide details on the location of the substation, the motivation for upgrading, and why the business could not use non-capital expenditure alternatives (such as maintenance or demand management).

The AER responds to these forecasts and makes a determination about the efficient required investment and operating costs. The AER then determines a revenue cap for the regulatory period, after taking account of the reasonable forecast spending, a rate of return on capital and a range of other matters.

The AER must reject operators' initial spending proposals if it is not satisfied that they reasonably reflect efficient, prudent and realistic spending decisions (as set out in s. 6.5.6 and 6.5.7 of the Rules), and frequently has done so. On the face of it, the AER has several grounds for rejecting a proposal. For example, s. 6.5.7(e) requires that, among other things, in deciding whether it is satisfied with a building block proposal for capital expenditure, the AER *must* have regard to its own analysis and to benchmarking of expenditure incurred by an efficient distribution business over the regulatory control period. Accordingly, the AER has been developing greater capabilities in benchmarking.[2]

Indeed, in various determinations, the AER has sought to check the reasonableness of forecasts of expenditure by using benchmarking. For instance, a study commissioned by the AER found that the current capital expenditure levels of the Victorian distribution businesses appeared relatively efficient when compared with expenditure levels in other states (Nuttall Consulting 2010 and AER 2010a, pp. 94-116). That finding, combined with the fact that historically the actual expenditure of these businesses was less than their prior forecasts, was cited as evidence that the new forecasts proposed by the businesses were likely to exceed the investments required.

However, a key question is the extent to which, in reaching a determination, the Rules limit the capacity of the AER to give prominence to its own separate analysis or benchmarking results compared with a forensic analysis of the distributor's building blocks proposal. The AER argues that it must base any alternative cost estimate on the original proposal, restricting the AER to 'conducting a detailed line by line assessment of the proposed forecast, rather than making a balanced assessment of all available information' (AER 2011b). In the Commission's early consultations, it was claimed that, in one instance, the AER had to evaluate the right number and cost of padlocks for substations.

The concern about such detailed assessment is amplified to the extent that information asymmetries between distributors and the AER undermine its capacity to make informed judgments (noting, however, that the AER is empowered to make information requests). Disquiet about such asymmetries is by no means exclusive to the Australian electricity market, but appears to be typical in any regime built on interpreting detailed building block data (Joskow 2008a, p. 554). If the AER's concerns about the dominance of the building blocks approach are well based, it could undermine the capacity for benchmarking to determine alternative estimates of forecast spending based on a more simple approach.

2 Material on information analysis from the AER website (http://www.aer.gov.au) accessed on 10 February 2011.

The AER also claims that the Rules inherently favour exaggerated estimates of costs rather than the best estimates. This is because the AER must approve a proposal where the spending *reasonably* reflects efficiency, prudence and rational expectations of demand and cost inputs. If it varies a proposal, it must do so only by the extent necessary. Accordingly, the AER must apply the highest cost that just meets the reasonableness criterion, rather than its best cost estimate.

Such a bias may be appropriate if the costs of regulatory error are greater for cost underestimates than cost overestimates. However, the bias (if material) poses challenges for the practical use of benchmarking analysis in determining costs. For example, the AER could select the best performer as the benchmark, or choose a benchmark close to, but not at the frontier.

It is notable that some Australian benchmarking suggests a vast gap between the results of the building blocks approach and those resulting from aggregate benchmarking exercises. Using the building block approach, the AER made downward adjustments to the spending forecasts by NSW electricity distributors that were relatively small against the background of what were very large investment increases. Yet benchmarking analysis based on inter-firm comparisons by Mountain (2011) and Mountain and Littlechild (2010) suggested that state-owned distributors in NSW would need to halve their expenditure to reach the level of efficiency of the privately-owned distributors in Victoria. When compared with best practice distributors in the United Kingdom, the claim was that government-owned distributors would have to cut their spending by 75 per cent to be efficient. Were the benchmarking results correct, it would mean the AER should only approve reduced capital expenditure amounts in subsequent regulatory periods, until the capital stock was optimised.

The apparent size of the gap is challenging for regulatory policy. It could mean that the building blocks approach was significantly awry. It could mean the same for the specific benchmarking analysis concerned. Both could be wrong by a large margin. Either way, such divergent results may not be of much assistance to the regulator, except to force it to look more closely at the numbers or to use an element of discretion and judgment, which is not allowed under the current Rules.

Given the above issues, an important consideration for the Commission is the extent to which the effective use of benchmarking would require complementary changes to the Rules.

It should be emphasised that network businesses and their peak bodies have strongly contested the AER's claims about flaws in the Rules, arguing that the

AER's concerns appear to reflect its interpretation of the Rules, rather than being an explicit feature of them.

Do the current Rules limit the use of benchmarking? If so, how do they do so, to what extent, and what would be the appropriate remedy?

In particular, do the Rules restrict the weight that the AER can apply to benchmarking analysis compared with the information that distribution business make available in the building blocks proposals? For example, could the AER reject the evidence from the building blocks analysis if it found compelling alternative evidence of lower required spending from benchmarking?

Must the AER forensically examine each aspect of the building blocks approach even if it believes that a more simple and robust benchmarking approach were available?

Are there any other limitations faced by the Australian Energy Regulator in using benchmarking, such as the merit review process?

What restrictions, if any, should apply to the AER's use of benchmarking or other analytical tools?

Should the AER select the best performer as the benchmark, or choose a benchmark close to, but not at the frontier? What criteria could be used to determine the threshold between unreasonable and reasonable costs?

In cases where the AER's benchmarking findings cast doubt on building block proposals but do not provide an exact alternative, should there be scope for the AER to negotiate a settlement with network businesses? How would that be achieved?

Could benchmarking reduce prescriptive regulation in the Rules? How? Which ones?

How would a regulator use benchmarking analysis that produced cost estimates significantly different from those from the building blocks approach? What approaches have other countries used in such instances?

Has the AER used benchmarking effectively? Should it adopt different practices? Are there any major process or resource obstacles to the AER's use of benchmarking?

Is there scope to introduce competition in parts of the electricity network? If so, where and when? Would that reduce any need for benchmarking in those parts? To *what extent could performance in competitive segments be used as benchmarks for non-competitive segments?*

A potentially excess cost of capital for regulated cost recovery

The Rules set out a particular approach to calculating the weighted average cost of debt and equity financed capital (WACC) applied to the regulated capital base (for example, s. 6.5.2 for distribution businesses). The WACC is an important component of the revenue cap applied by the AER over the regulatory period.

Notwithstanding the high degree of prescription, there have been disagreements between network businesses, the AER and user groups about the detailed aspects of the WACC — leading to very different estimates. Most of the merit reviews sought by distributors have focused on the AER's determinations of the WACC. Generally, the Australian Competition Tribunal has overturned the AER's estimated WACC, with decisions that have added around $3 billion to electricity bills since June 2008 (AER 2011a, p. 8). The AER and the Energy Users Association of Australia (EUAA) claim that there are faults in the methodology for calculating the WACC, and have sought a Rule change (AEMC 2011c). The EUAA claim there are very large margins between the allowed cost of debt in the WACC and its appropriate rate (suggesting that the margin is 250 basis points for private network businesses and 350 basis points for government-owned businesses).

While views differ, there is particular concern about the implications of any errors in the WACC on the behaviour of network businesses, which in turn affects the extent to which the existing Rules create incentives for cost minimisation.

In *theory*, the Rules create such incentives because, having locked in an allowed revenue amount over a regulated period, a business can increase its profits if it can meet the supply requirements more efficiently. It would do this by spending less than the forecast capital or operating expenditure, such as by adopting innovative practices, finding less costly non-network solutions or improved procurement processes. In a single regulatory period, prices may still be higher than in a perfectly competitive market. However, the losses from high prices usually have less important efficiency effects (reflecting low demand responses) compared with the losses associated with the absence of strong cost minimising incentives — a point made by Joskow (2008, p. 549). In any case, in subsequent regulatory periods, resets of approved spending should result in convergence to expenditures and prices that would mimic a competitive environment.

However, in *practice,* the capacity for the above incentive arrangements to encourage cost minimisation depends on the:

- way that the Rules treat forecast errors in capital expenditure. During any regulatory period, a network business that spends more than the forecast capital expenditure must raise capital for funding the additional investment, without any return from the revenue cap. However, in the subsequent regulatory periods, the depreciated value of the additional spending is rolled into regulatory asset base, with the business earning the regulated rate of return on these assets for the remainder of (their typically long) lives. There is no requirement for an ex post asset utilisation or prudency review by the AER, nor a requirement for the asset to be adjusted according to the degree of utilisation of an asset (AEMC 2011b)
- tradeoff between the costs to the business of uncompensated investment in the first regulated period compared with the benefits of regulated compensation for all subsequent periods.

Some contend that the tradeoff is different between private and government-owned businesses reflecting that:

- the cost of financing is lower (and availability greater) for government-owned businesses than private ones, tilting the former towards investments that exceed forecast spending
- the spending behaviour of government-owned businesses may partly reflect non-financial objectives implicitly or explicitly set by governments (such as employment, procurement and environmental goals, and higher than efficient reliability standards). Some stakeholders have suggested that to the extent that the WACC exceeds its appropriate value, governments can actually benefit from stipulating such objectives since they can raise dividends (and corporate tax transfers) from their government-owned electricity businesses.

The data on forecast versus actual spending suggest that private distribution business spend less than their forecasts, while regulators claim that there have been large capital overspends in NSW and Queensland, where the distribution businesses are all government-owned (AER 2011a, p. 7; IPART 2010, p. 55).

The effects of any errors in (or different views about) the WACC may be relevant to benchmarking in several ways:

- To the extent that the WACC is excessively high, and businesses are able to roll in overspends in one period into the next, it might be difficult to use benchmarking as a tool for creating incentives to cost minimise without modifying the Rules. If the Rules and/or ownership arrangements undermine the capacity for incentive regulation then they can lead to the kind of cost padding usually associated with primitive rate of return regulations (first analysed by Averch and Johnson in the early 1960s).

- There may be grounds for testing the relative efficiency of government-owned versus private network companies through benchmarking to assess how the WACC might be set for the different businesses, to provide a transparent picture of the costs of realising any non-financial objectives of government-owned businesses, to assess whether and why their behaviours are different, and to gauge the impacts of existing ownership arrangements.

To what extent, if any, are there flaws in the AER's current benchmarking of the WACC, and if so, how could it be improved?

Is there evidence that the regulatory WACC should be different for government-owned compared with private network businesses? What implications would differential WACCs have for the eventual privatisation of such businesses?

What, if any, are the effects of the various WACC determinations on:

- *the incentives of private versus government-owned network businesses?*
- *choices about spending on capital expenditure versus operating expenditures?*

How can the different patterns between forecast and realised spending between private and government-owned network businesses be explained?

How does the efficiency of private distribution businesses compare with government-owned ones, and if different why and how would this be remedied?

Do government-owned network businesses have any non-commercial objectives? How do these vary by business type or jurisdiction? How do they affect the behaviour or efficiency of the businesses? Should they be removed or altered? Should they be factored into benchmarking analysis?

While government-owned businesses pay corporate taxes to state governments — consistent with competitive neutrality principles — are those principles undermined by the shareholder status of governments or any other governance issues? Does that affect investment decision-making by government-owned businesses or the determination of reliability standards and other policies by governments?

If any biases towards excessive investment posed by the WACC and the rollover arrangements of the regulated asset base were removed, would that eliminate the need for further development of benchmarking?

Reliability standards and planning

Reliability standards also affect efficiency.

Power can be interrupted for several reasons. A tree can brush against a power line, resulting in a brief power cut (of seconds) until equipment incorporated in the system re-energises the temporarily faulty line. Insufficient voltage may cause 'brownouts' (which affects the operation of electrical equipment). A blackout occurs where there is an excess of demand over supply in the electricity system, and the system operator shuts down parts of the system, usually in a controlled way ('load shedding'). In Victoria in 2007, heat wave conditions led to surging demand for electricity and fires that damaged the major transmission line connecting Victoria and NSW. The resulting blackouts affected 200 000 people and led to the failure of traffic lights and rail systems, illustrating the consequences of system failures. 'Cascading' failures, where a failure in one part of the system overloads the remaining links (Joskow 2008b), can potentially lead to catastrophic power outages, as occurred in Italy in 2003, which clearly governments wish to avoid.

Network providers reduce the risks of power outages in many ways. Steel-grounded shield conductors on transmission towers protect transmission lines from lightning strikes. Automated fault correction equipment means many outages last only a few seconds. Most importantly, planners build spare capacity into the network so that when a fault occurs, the number of customers affected is minimised. This spare capacity is known as 'redundancy' or 'the reserve requirement' and, though rarely used, contributes to the reliability of the electricity system.

Most Australian jurisdictions use the so-called 'deterministic' approach to reliability, which identifies the lowest cost option to achieve given reliability standards for various parts of the network. Generally, these options reflect customer density and the costs of failure in different parts of the system. The deterministic approach does not consider the net economic benefits of achieving the given reliability standards. In Victoria, an alternative 'probabilistic' approach is used. Network augmentations are only undertaken when the probability of a fault occurring multiplied by the likely economic cost incurred by customers is greater than the cost of augmenting the system (that is, there is a net benefit to the augmentation).

Networks built to a reliability standard under a deterministic framework generally (although not always) have more redundancy than those built under a probabilistic framework. The main practical difference between the two approaches is that network augmentation is more likely to be made later under probabilistic planning — which can still entail considerable cost savings.

Incentive arrangements based on rewards or penalties for network providers that deviate from a service benchmark apply in some instances (the f-factor scheme for fire prevention in Victoria and the 'service target performance incentive scheme' in the NEM). In theory, if the benchmark and the incentives are correctly set, this approach can reduce the need for prescriptive reliability standards.

Different standards and planning approaches set by governments can therefore affect the cost of networks, and since such costs are recouped from customers, the ultimate prices for electricity. The high long-run marginal costs of additional redundancy means that relaxing reliability standards can lead to large cost savings — savings which may be greater than the lost value of reliability to customers. IPART identified more stringent license standards in NSW electricity distribution as sources of additional capital expenditure and lowered productivity (IPART 2010). Energex indicated that relaxing the strict standards required in Queensland for some parts of its network could lead to savings of up to $250 million in the current regulatory period (Somerville 2011, p. 32; pp. 49ff), although the net economic benefits would be less than this, given consumers place at least some value on reduced reliability.

Currently, the AER takes reliability standards as given in making its revenue cap determinations. Following that principle would mean that it would control for different reliability standards in benchmarking. However, as noted above, a broader view of benchmarking might consider the costs imposed by standards (relative to their benefits), which in turn would be used to inform policy change.

To what degree do different jurisdictions' reliability standards affect costs, if at all? Do different standards affect the potential and/or incentives for a single network business to extend its network across borders?

Why have reliability standards been increased over time, and what impacts have these increases had on costs?

To what extent would adoption of a probabilistic versus deterministic framework change costs? What risks and benefits would this entail?

What evidence is there of customer involvement (such as willingness to pay) in setting reliability standards?

How are existing reliability incentive schemes functioning and how could benchmarking contribute to their design?

What is an appropriate governance structure for setting and monitoring reliability standards, and what is the rationale or evidence base for different standards across jurisdictions?

To what degree should a jurisdiction that specifies a higher reliability standard than others justify such a requirement to its constituents based on a transparent cost-benefit analysis?

Demand-side management

Demand-side management aims to reduce network and generation costs by changing the pattern of consumption. It usually intends to shift consumption away from peak demand periods, as these drive marginal generation costs and network augmentation. One of the criticisms made by Garnaut (2011) is that network investment has been used too readily in Australia to meet rising peak demand (notwithstanding static or even falling overall electricity consumption), when demand-side management might have been more efficient.

While estimates vary across jurisdictions, around 25 per cent of retail electricity costs are accounted for by temperature driven peak demand events that occur for less than 40 hours per year (NESI 2011). Trials and case studies of demand-side management identify potential reductions in peak demand usually in the order of 5 to 40 per cent. Evidence on how this impacts network spending is limited, but one Australian study suggests avoidable infrastructure costs of around 5 per cent, simply from delaying capital investment on a project by one year through demand response initiatives (CRA 2004).

Demand-side management is achieved through a wide range of strategies (Energy Futures Australia 2008). These include energy efficiency measures; arrangements for reducing loads on request; fuel switching (such as moving from electricity to gas for heating purposes); direct load control (such as remote control of air conditioning); distributed generation (such as roof-top photovoltaic cells); and time-of-use pricing (or rebates). It is underpinned by provision of information to consumers, technologies (like interval metering and smart meters), and incentives to electricity businesses to use these strategies. Several government-funded trials of demand management are underway.

One goal of benchmarking would be to examine the extent to which network owners had engaged in optimal demand-side management. However, as in some other areas of network benchmarking, the regulatory environment may frustrate such an exercise, including:

- regulations that favour traditional network investment (so that the ideal level of demand-side management may not be apparent in the market as an observable benchmark)
- constraints by governments about using price signals. For example, despite the widespread introduction of smart meters, the Victorian Government has introduced a moratorium on time-of-use pricing. In all other jurisdictions, retail price caps continue to persist, despite agreement by governments to a process for their removal
- deterministic reliability standards that require distributors to build spare capacity, even if demand-side management might be a more efficient solution
- the degree to which the AER could (or would) take into account the fact that the benefits of a distributor's investments in demand-side management may be partly appropriated by transmission businesses and generators.

Accordingly, one step might be an exercise in regulatory benchmarking — comparing the cost and efficiency outcomes of the current regulatory regime with those where the regulatory obstacles to demand-side management had been removed. That in turn could lead to regulatory reform, followed by inter-firm benchmarking to assess how various distributors behaved once the 'ideal' regulatory system was in place, and use by the regulator of incentives for businesses to improve their performance through the design of the regulatory revenue cap.

Even were neither of the above steps taken, a further option might be to assess the degree to which recent distribution investment could realistically have been addressed by demand-side management. Such an exercise recognises that there are many practical obstacles to demand-side management as a measure to defer network investments even were an ideal regulatory system in place (such as customer acceptance and lack of certainty by network distributors about actual customer behaviour on peak load times).

What role could demand management play in reducing peak demand, how would it work, how much would it cost, and what network savings would be experienced? In which parts of the network are cost savings most likely and why?

What are the regulatory and other obstacles to demand management or other approaches that give consumers choice? How are these changing?

How do network providers model and make financial decisions about the impact of peak demand growth on network adequacy, including identification of the most cost-effective network investment solution (for a given reliability standard)?

How could benchmarking or other tools identify the degree to which network businesses have efficiently used demand-side management as substitutes for building redundancy in their networks?

What is the evidence about the effectiveness and customer acceptance of demand management provided by the various trials and experiments in Australia and internationally? What factors have inhibited the use of already installed smart meters?

6 Interconnector issues

Interconnectors transmit high voltage power between the jurisdictions in the NEM. There are six interconnectors, linking Queensland and NSW, Victoria and Tasmania, Victoria and South Australia, and Victoria and NSW. Without interconnectors, there would be no trading in electricity between the states, and therefore no NEM. Instead, there would be a set of autonomous regionally-based electricity markets.

The advantage of trade in electricity is similar to trade in other goods and services. Jurisdictions with excess (base or peak load) capacity or with lower cost electricity generation can export it to markets with insufficient capacity. For example, Queensland's installed capacity exceeds its demand for peak load, so that it can export power to NSW during peak load periods (such as during a heat wave). In turn, trade can lower average electricity prices and may improve system reliability (depending on whether intra-state transmission networks can support interstate supply during peak demand periods). Interconnection may also defer transmission investment in the importing state.

Under the market arrangements, generators from all regions can compete to meet demand in any given region at any point. However, the spot prices arising from bidding in different state markets may vary because of capacity bottlenecks in interconnectors (the main reason) and due to adjustment of bid prices for transmission losses. Consequently, AEMO may not despatch low cost generators in a given state if there is a bottleneck on the interconnector or elsewhere in the network (AEMC 2008). In most cases, the prices of the regional markets align (around 60 per cent of the time in 2010-11). However, alignment has fallen over time, reflecting congestion on interconnectors (AER 2011a, p. 34). So-called 'price separation' mainly arises during periods of peak demand or when maintenance of the interconnectors occurs.

Unlike some concerns about over-investment in within-region network investment, the AEMC has noted stakeholder apprehension about under-investment in interconnectors (Smith 2011). In his 2008 review, Garnaut considered that the role of interconnectors in an efficient NEM would increase because it would change price differences between competing high-carbon emitting generators and low-emitting ones located in different jurisdictions (Garnaut 2008, p. 446). These concerns are not peculiar to Australia. Economists have claimed that interconnector investment failure has also weakened the scope for a properly functioning electricity market across the European Union (Kapff and Pelkmans 2010).

As part of its current review of the transmission framework, the AEMC has sought evidence from stakeholders about what constraints may exist. Some stakeholders suggest that upgrades in interconnectors are already being considered, which may make any new policy changes premature (AEMC 2011d, p. 131).

Moreover, some price separation may be efficient, reflecting that the costs of building and maintaining interconnectors may outweigh the gains of accessing lower cost generation from other regions. In addition, the process for forecasting transmission demand is inherently uncertain, so that capacity constraints may reasonably emerge when past investments do not match future demand. That would not necessarily be a market failure. Notably, at the time of its planning, the interconnector between NSW and Queensland was intended to transfer excess power from NSW to Queensland. However, due to expansion of generator capacity in Queensland, the net flows ultimately went the other way.

The real issue is whether the current regulations would ensure that an interconnector would be built if it were efficient to do so. That would take account of whether there were other more efficient options, such as doing nothing or investing in new conventional generation capacity, demand management, intra-regional transmission or distributed generation.

Some stakeholders argue that there are significant constraints on the efficient use of interconnectors. Some of the issues raised by the AEMC and others are:

- whether transmission businesses should take into account interconnector capacity when considering investment *within* a region. Investments in regional transmission can enhance (or undermine) the potential of interconnectors to fulfil their role, and yet that potential may receive little weight in transmission businesses' investment decisions (AEMC 2011d, p. 138). One suggested solution was to give transmission businesses the responsibility to ensure that the interconnector capability was appropriately considered as part of their planning process

- weaknesses in transmission planning
- the degree to which the current open access regime for generators connecting to the transmission network results in localised congestion on that network, constraining the role of interconnectors (AEMC 2011d, p. 60)
- the differences in the regulatory arrangements for wires with different thickness and load carrying capacity — the intra-regional high voltage lines ('transmission'), inter-regional high voltage lines (interconnectors) and lower voltage lines (distribution)
- whether state governments frustrate the development of interconnectors to protect their own high-cost generators and secure higher dividend streams to government coffers (Garnaut 2008, p. 448). Interconnectors mean that high-cost plants will secure less (or even no) demand in certain market periods if a competing lower-cost interstate generator can meet the capacity need at lower costs. A related (and offsetting) implication is that an importer of electricity will secure lower prices for their consumers, so state governments would have to balance the revenue gains from barriers to trade with the cost imposed on end users (as for import barriers in international trade)
- whether generators on one side of the border sometimes wield market power through the spot price bidding process to reduce the viability or attractiveness for investment of generators on the other side of the border
- since interconnectors must always span two states, there must be agreement about upgrades or the construction of interconnectors. However, state governments and transmission planners may have varying views about the reliability benefits and other gains of interconnectors, which can affect their motivation to negotiate with each other (Garnaut 2008, p. 448)
- whether there are particular obstacles to unregulated privately-initiated investment in interconnectors ('merchant' interconnectors). Historically, some unregulated merchant interconnectors have proceeded (such as Murraylink between South Australia and Victoria). However, these have not all been seen (ex post) as good investments, noting that under existing commercial arrangements, interconnectors may not be able to secure all of the benefits of their investments, such as those that improve system reliability (Littlechild 2011, p. 15). In fact, Murraylink applied for transfer from merchant to regulated status two weeks after commencement of its commercial operations. Regulated interconnectors passing the regulatory test receive a fixed annual return based on the value of their assets, regardless of whether these are used. That insulates them from risk, and depending on the details of the test, may crowd out potentially lower cost merchant interconnectors

- whether the test used to approve regulated interconnectors counts all the long-run economic benefits. On the other hand, some have argued that the test is already too complex and long-winded, and actually frustrates the realisation of economically viable projects.

It may be that changes to regulatory arrangements could increase the scope for privately-initiated interconnectors, or at least reveal whether they are genuinely economic. For example, following electricity reform, Argentina chose a radical approach — the Public Contest method.[3] All major transmission infrastructure had to be provided on a merchant basis. Any market participant that was a beneficiary (primarily generators and electricity distributors), had to propose, vote for and pay for all major expansions, with the suppliers of services determined through competitive tendering. Littlechild (2011) has argued that many of the problems that could *theoretically* affect merchant interconnectors did not emerge in practice. In contrast, in other countries — including Australia — Littlechild claimed that there were many problems associated with regulated interconnectors (supposedly slow bureaucratic processes, technological conservatism, cost padding and lobbying). This is a complex area, where major disagreements persist (such as those by Joskow and Tirole 2005, who doubt the general viability of merchant transmission).

It should also be noted that even economic appraisals of the benefits of interconnectors is highly complex and costly (with feasibility studies sometimes costing the equivalent of millions of dollars — Turvey 2006a). This also suggests that it is difficult to estimate the benefits of any policy change. However, some empirical methods have been used to assess the potential for interconnectors to achieve greater market integration and lower prices (Nepal and Jamasb 2011). Such empirical measures may be useful in assessing whether existing interconnector arrangements are deficient.

To what degree are interconnectors important to greater competition and greater efficiency in the NEM (once account is taken of the costs of construction and any collateral investments required)?

What is the magnitude of the impacts on prices, generator capacity and the use of renewable power arising from any deficiencies in interconnector investment? In effect, do any flaws matter much?

What empirical methods could be used to indicate the scope for further interconnectors?

[3] Arrangements have since changed in Argentina.

What are the obstacles to efficient interconnector investment and how could these be overcome?

Are current coordination and planning arrangements efficient?

If more interconnection is efficient, how much and where would the additional capacity be built?

Why should regulations for transmission and distribution investment be different?

What are the advantages and disadvantages associated with various options to improve interconnector efficiency, taking into account that some potential solutions (such as public contest methods) may have far-reaching impacts on other parts of the market? What changes in distribution and transmission regulation would be required to permit more market-based interconnector arrangements?

To what extent is it likely that prospective upgrades in interconnection capacity will resolve the currently perceived problems without a need for policy changes? Are longer-term policy changes required to ensure longer-term upgrades?

Will the value of greater interconnector capacity rise as carbon pricing creates larger cost margins between competing generators located in different states? If so, to what extent?

Given the AEMC's ongoing review of the transmission framework, where can the Commission add the most value to interconnector policy issues?

What are the lessons from other countries' approaches to interconnector investment, including the Argentinian approaches and the new cost allocation principles of the United States Federal Energy Regulatory Commission (Order 1000) released in July 2011?

Taking account of the costs of interconnectors and their transmission losses, to what extent could congestion and price separation events be better addressed by alternatives, such as more investment in transporting gas to gas-fired generators, or by using distributed generation? Are there barriers to such alternatives?

7 The role of generators

The location, type, and conduct of generators may affect the configuration and performance of the electricity network.

For example, generators have a stake in demand management, which has benefits for network efficiency. Renewable power generation and micro generation may affect the design of the network. Some have claimed that generators can behave strategically, which may frustrate interconnector investment. Others have pointed to the difficulties, under the current open access arrangements, that generators experience in securing property rights over new transmission infrastructure — which might lead to underinvestment in cases where transmission largely benefits one generator. Any flaws in the existing market arrangements for determining electricity spot prices and transmission loss factors might influence generator viability and the location of dispatched generators — again with possible implications for network efficiency.

To what degree does the type, location and conduct of generators affect the efficiency of the electricity network? What are the implications of any such impacts?

How would benchmarking of network businesses, or its application in regulations, take into account any such complexities?

8 Accounting for the future

The inquiry is taking place in a context where network and generation technologies are changing. Climate change policy will alter the costs of power generation, and over the longer-run, the type and location of generators. Some forms of local small-scale power generation may provide direct power to customers, without significant network infrastructure, thus providing competition. On the other hand, some local generation — such as through rooftop photovoltaic panels — may impose some network costs, given that the grid is currently designed for one-way power traffic.

While likely to be some way off in Australia, electricity grids are becoming increasingly smart, with the digital collection of information about the performance of the grid and of customer behaviour, and with technologies that can respond to this information (the ‘smart grid’).

Moreover, there may be future mergers and privatisation of network businesses, which can alter management incentives, capital access and complicate historically based benchmarking.

Collectively, these changes are likely to affect the utilisation and nature of the network system that transports the power, and the ultimate prices borne by end users.

What are trends in electricity supply and how will these affect regulation, and the need for, and use of, benchmarking and other regulations?

To what extent, if at all, will renewable generation and household feed-in tariffs require network upgrades. How costly and efficient would it be?

Is local small-scale power generation likely to develop cost-effectively to such a degree that it (a) erodes the distribution network natural monopoly (b) significantly reduces network investment requirements? If so, how long before this happens, with what technologies and costs, and with what implications for regulation? Are there obstacles to efficient distributed generation?

How fast will Australia move towards 'smart grids'? How much will these cost, and what impacts will they have on reliability and overall network investment? Will they provide better evidence about the comparative performance of different network providers?

There may be greater future scope for the regulator to scrutinise the regulated asset base to judge whether capital is efficiently used and, if not, to reduce the regulated asset base. The capacity for ex post scrutiny could be reinforced if the informational and methodological constraints on benchmarking were significantly reduced over the longer run. Ex post assessment would reduce ex ante incentives for any over-investment (Biggar 2011, p. 47). Indeed, even the announcement of an intention to use some ex post analysis — if deemed reliable enough — may create *current* incentives for network providers to invest efficiently over the immediate regulatory period. That possibility is strengthened by the fact that network investments are long-lived.

However, there may be significant practical difficulties in using ex post scrutiny of investment, and risks to efficient investment if the tests are seen as likely to incorrectly identify excess investment.

To what degree could the likely future development of better benchmarking tools be incorporated into current incentive regulations to reduce any bias towards excessive investment? How should any such incentive regulations be designed? What are the major advantages and disadvantages of such incentive arrangements, and in particular the magnitude of any risks that such an approach could chill efficient investment? Are there any similar arrangements in utilities or other regulations that provide lessons on such incentive arrangements?

9 Implementation issues

New benchmarking and interconnector approaches and complementary (or substitute) rule changes may take time and require extensive coordination.

How should policy change be implemented, what are the priorities and how long will it take? Is there a critical sequence of changes that should take place?

Are there significant costs in implementing change?

Which agencies/parties should do what when implementing change?

Is there any interaction with other policies/regulations that would affect the effectiveness of implementation?

Given the experience of the last five to 10 years, over the longer term, how should the NEM be modified to meet the best interests of consumers?

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